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Preventing Undue Discrimination and Preference in Transmission Service; Proposed Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35 and 37

[Docket Nos. RM05–25–000 and RM05–17–000]

Preventing Undue Discrimination and Preference in Transmission Service

May 19, 2006.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is proposing amendments to its regulations adopted in Order Nos. 888 and 889, and to the *pro forma* open access transmission tariff, to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential.

DATES: Comments are due August 7, 2006. Reply comments are due September 5, 2006.

ADDRESSES: You may submit comments, identified by Docket Nos. RM05–25–000 and RM05–17–000, by one of the following methods:

- Agency Web site: *http://www.ferc.gov.* Follow the instructions for submitting comments via the eFiling link found in the Comment Procedures section of the preamble.
- Mail: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE., Washington, DC 20426. Please refer to the Comment Procedures section of the preamble for additional information on how to file paper comments.

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I. Introduction

1. Ten years have passed since the Commission issued its landmark Order No. 888.[1] Named after our new headquarters in Washington, DC, Order No. 888 sought to eradicate undue discrimination in the provision of transmission service in interstate commerce. It did so by requiring that each public utility that owns, operates, or controls facilities used for transmission in interstate commerce offer unbundled transmission service pursuant to a standard Open Access Transmission Tariff (*pro forma* OATT) and separate its transmission and merchant generation functions pursuant to a companion order issued that same day, Order No. 889.[2] These remedies reduced barriers to entry, led to greater competition in bulk power markets and provided the foundation for subsequent regulatory reforms at both the federal and state level.

2. Although Order No. 888 has been successful in many important respects, the need for reform of the Order No. 888 *pro forma* OATT has been apparent for some time. In 1999, the Commission held, in adopting Order No. 2000,[3] that

[1] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000) (*TAPS* v. *FERC*), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[2] *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct,* Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g,* Order No. 889–A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g,* Order No. 889–B, 81 FERC ¶ 61,253 (1997).

[3] *Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001).

the *pro forma* OATT could not fully remedy undue discrimination because transmission providers retained both the incentive and the ability to discriminate against third parties, particularly in areas where the pro forma OATT left the transmission provider with significant discretion.[4] The Commission in Order No. 2000 thus encouraged utilities to voluntarily join independent regional transmission organizations (RTOs) that would operate their transmission facilities on a non-discriminatory basis and administer the OATT. The Commission based Order No. 2003 on a similar finding, explaining that the interconnection process includes opportunities for undue discrimination that may lead to delays that benefit generation-owning transmission utilities and undermine competition.[5] While many regions of the country now have independent grid operators, not all do, and changes to the pro forma OATT are necessary to reduce the opportunity for transmission providers to engage in undue discrimination. In the past ten years new investment has faltered and many regions now experience chronic transmission congestion and inadequate infrastructure. Congress, through the Energy Policy Act of 2005 (EPAct 2005),[6] recognized this problem and provided the Commission not only new tools to encourage infrastructure but also made clear that the Commission should use its existing authority to ensure an adequate infrastructure to support a vibrant economy.

3. The reforms we propose today are intended to address deficiencies in the *pro forma* OATT that have become apparent since 1996 and to facilitate improved planning and operation of transmission facilities. We summarize these reforms in Part IV.A below, but note the major focus of this reform effort here. As a general matter, the purpose of this rulemaking is to strengthen the *pro forma* OATT to ensure that it achieves its original purpose—remedying undue discrimination—not to create new market structures. We propose to achieve this goal by increasing the clarity and transparency of the rules applicable to the planning and use of the transmission system and by addressing ambiguities and the lack of sufficient detail in several important areas of the pro forma OATT. The lack of specificity in the pro forma OATT creates opportunities for undue discrimination as well as making the undue discrimination that does occur more difficult to detect. First, we propose to improve transparency and consistency in several critical areas, such as the calculation of available transfer capability (ATC).[7] We propose to direct public utilities, under the auspices of the North American Electric Reliability Council (NERC) and the North American Energy Standards Board (NAESB), to provide for greater consistency in ATC calculation. By reducing unnecessarily broad discretion in this and other areas, we will reduce the ability of transmission providers to unduly discriminate and provide them greater certainty to facilitate compliance with our regulations. Second, we propose to reform the transmission planning requirements of the *pro forma* OATT to eliminate potential undue discrimination and support the construction of adequate transmission facilities to meet the needs of all load-serving entities. The *pro forma* OATT contains only minimal requirements regarding transmission planning, which have proven to be inadequate as the Nation faces inadequate transmission investment in many areas. We propose to require public utilities to engage in an open and transparent planning process at both the local and regional levels. Third, we propose to remedy certain portions of the *pro forma* OATT that may have permitted utilities to discriminate against new merchant generation, including intermittent generation. For example, we propose to modify the energy imbalance provisions of the *pro forma* OATT and adopt certain other tariff modifications. Fourth, we provide for greater transparency in the provision of transmission service to allow transmission customers better access to information to make their resource procurement and investment decisions, as well as to increase our ability to detect any remaining incidents of undue discrimination. Finally, we provide for reform and greater clarity in areas that have generated recurring disputes over the past 10 years, such as rollover rights, ''redirects,'' and generation redispatch.

4. Although the reforms being proposed in these areas are significant, we wish to underscore that we propose to maintain many of the core elements of Order No. 888. For example, we are retaining the comparability requirement under which each public utility must treat third parties in a manner comparable to its service to bundled customers. We are retaining the basic nature of the services being offered—network service and point-to-point service. We are retaining the protection of native load customers embodied in Order No. 888, consistent with EPAct 2005's new requirement that load-serving entities be provided transmission rights to meet their service obligations.[8] We are retaining our decision to exercise jurisdiction over unbundled transmission service, but not transmission service provided as part of a bundled retail service. We are retaining the use of functional unbundling to address undue discrimination, rather than requiring corporate unbundling. We are retaining the use of an OATT to facilitate the development of competitive wholesale markets by reducing barriers to entry through the control of transmission assets, not imposing any particular market structure on the industry.

5. In proposing to reform Order No. 888, we have relied heavily on the comments received in response to our notices of inquiry in the above-captioned dockets.[9] We appreciate the time and thoughtfulness of all sectors of the industry in preparing comments on these notices of inquiry. We have found them very informative and useful and this Notice of Proposed Rulemaking (NOPR) incorporates many of the commenters' suggestions. We invite further comments on this NOPR. We also are scheduling technical conferences to more fully address the topics of ATC calculation and transmission planning.

II. Background

A. Historical Antecedent

6. In the first few decades after enactment of the Federal Power Act (FPA) in 1935, the industry was characterized mostly by self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities,

[4] Order No. 2000 at 31,015.

[5] *See* Order No. 2003 at P 11–12.

[6] Pub. L. 109–58, 119 Stat. 594 (to be codified in scattered itles of the U.S.C.).

[7] We note that the Commission used the term ''Available Transmission Capability'' in Order No. 888 to describe the amount of additional capability available in the transmission network to accommodate additional requests for transmission services. To be consistent with the term generally accepted throughout the industry, the Commission is proposing to revise the *pro forma* OATT to adopt the term ''Available Transfer Capability.''

[8] EPAct 2005 sec. 1233 (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q).

[9] *Preventing Undue Discrimination and Preference in Transmission Services*, Notice of Inquiry, 112 FERC ¶ 61,299 (2005) (NOI); *Information Requirements for Available Transfer Capability*, Notice of Inquiry, 111 FERC ¶ 61,274 (2005) (ATC NOI).

and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities connected to each utility's transmission system. Each system covered a limited service area, which was defined by the retail franchise decisions of state regulatory agencies. This structure of separate systems arose naturally due primarily to the cost and technological limitations on the distance over which electricity could be transmitted.

7. A number of statutory, economic, and technological developments in the 1970s led to an increase in coordinated operations and competition. Among those was the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA),[10] which was designed to lessen dependence on foreign fossil fuels by encouraging the development of alternative generation sources and imposing a mandatory purchase obligation on utilities for generation from such sources. PURPA also enabled the Commission to order wheeling of electricity under limited circumstances.[11] The rapid expansion and performance of the independent power industry following the enactment of PURPA demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power. During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. The economic and technological changes in the transmission and generation sectors helped encourage many new entrants in the generating markets that could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, it became increasingly clear that the potential consumer benefits that could be derived from these technological advances could be realized only if more efficient generating plants could obtain access to the regional transmission grids. Because many traditional vertically integrated utilities still did not provide open access to third parties and favored their own generation if and when they provided transmission access to third parties, access to cheaper, more efficient generation sources remained limited.

8. The Commission encouraged the development of independent power producers (IPPs), as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis and by encouraging more widely available transmission access on a case-by-case basis. Market-based rates helped to develop competitive bulk power markets by allowing generating utilities to move more quickly and flexibly to take advantage of short-term or even long-term market opportunities than those utilities operating under traditional cost-of-service tariffs. In approving these market-based rates, the Commission required that the seller and its affiliates lack market power or mitigate any market power that they may have possessed.[12] The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby drive up prices. A key inquiry became whether the seller or its affiliates owned or controlled transmission facilities in the relevant service area and therefore, by denying access or imposing discriminatory terms or conditions on transmission service, could foreclose other generators from competing. Beginning in the late 1980s, in order to mitigate their market power to meet the Commission's conditions, public utilities seeking Commission authorization for blanket approval of market-based rates for generation services under section 205 of the FPA filed ''open access'' transmission tariffs of general applicability.[13] The Commission also approved proposed mergers under section 203 of the FPA on the condition that the merging companies remedy anticompetitive effects potentially caused by the merger by filing ''open access'' tariffs. The early tariffs submitted in market-based rate proceedings under section 205 and merger proceedings under section 203 did not, however, provide access to the transmission system that was comparable to the service the transmission providers used for their own purposes. Rather, they typically made available only point-to-point transmission service, *i.e.*, service from a single point of receipt to a single point of delivery. As these early tariffs were offered only by transmission providers that volunteered to provide service to third parties, they resulted in a patchwork of open access that was not sufficient to facilitate wholesale generation markets.

9. In response to the competitive developments following PURPA, and the fact that limited transmission access and significant regulatory barriers continued to constrain the development of generation by independent power producers, Congress enacted Title VII of the Energy Policy Act of 1992 (EPAct 1992).[14] EPAct 1992 reduced regulatory barriers to entry by creating a class of ''Exempt Wholesale Generators'' that were exempt from the requirements of the Public Utility Holding Company Act of 1935.[15] EPAct 1992 also expanded the Commission's authority to approve applications for transmission services under sections 211 and 212 of the FPA. Though the Commission aggressively implemented expanded section 211, it ultimately concluded that the procedural limitations in section 211 thwarted the Commission's ability to effectively eliminate undue discrimination in the provision of transmission service.

B. Order No. 888 and Subsequent Reforms

10. In April 1996, as part of its statutory obligation under sections 205 and 206 of the FPA to remedy undue discrimination, the Commission adopted Order No. 888 prohibiting public utilities from using their monopoly power over transmission to unduly discriminate against others. In that order, the Commission required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs that contained minimum terms and conditions of non-discriminatory service. It also obligated such public utilities to ''functionally unbundle'' their generation and transmission services. This meant public utilities had to take transmission service (including ancillary services) for

[10] Pub. L. 95–617, 92 Stat. 3117 (1978) (codified in U.S.C. titles 15, 16, 26, 30, 42, and 43 (2000)).

[11] Section 211 of the FPA, 16 U.S.C. 824j (2000). In earlier years, a few customers were able to obtain access as a result of litigation, beginning with the U.S. Supreme Court's decision in *Otter Tail Power Company* v. *United States*, 410 U.S. 366 (1973). Additionally, some customers gained access by virtue of Nuclear Regulatory Commission license conditions and voluntary preference power transmission arrangements associated with federal power marketing agencies. *See, e.g.*, *Consumers Power Co.*, 6 NRC 887, 1036–44 (1977); *Toledo Edison Co.*, 10 NRC 265, 327–34 (1979); *Florida Municipal Power Agency* v. *Florida Power and Light Company*, 839 F. Supp. 1563 (M.D. Fla. 1993).

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

[13] *See* Order No. 888 at 31,644 n.52.

[14] Pub. L. 102–486, 106 Stat. 2776 (1992) (codified at, among other places, 15 U.S.C. 79z–5a and 16 U.S.C. 796 (22–25), 824j–l (2000)).

[15] 15 U.S.C. 79a (2000), *repealed by* EPAct 2005 sec. 1263; *see Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005*, Order No. 667, 70 FR 75592 (Dec. 20, 2005), FERC Stats. & Regs. ¶ 31,197 (2005).

their own new wholesale sales and purchases of electric energy under the open access tariffs, and to separately state their rates for wholesale generation, transmission and ancillary services.[16] Each public utility was required to file the *pro forma* OATT included in Order No. 888 without any deviation (except a limited number of terms and conditions that reflect regional practices).[17] After the effectiveness of their OATTs, public utilities were allowed to file, pursuant to section 205 of the FPA, deviations that were consistent with or superior to the *pro forma* OATT's terms and conditions. Because certain owners and controllers or operators of interstate transmission facilities were not subject to the Commission's jurisdiction under sections 205 and 206 and thus were not subject to Order No. 888, the Commission adopted a reciprocity provision in the *pro forma* OATT which conditions the use by non-public utilities of public utilities' open access services on an agreement to offer open access services in return.

11. In addition to imposing the functional unbundling requirement, the Commission also encouraged broader reforms through the formation of independent system operators (ISOs). The Commission stated that ISOs ''have the potential to provide significant benefits (*e.g.*, to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power) and will further our goal of achieving a workably competitive market.'' [18] While the Commission declined to mandate ISOs, it set forth eleven principles for assessing ISO proposals submitted to the Commission.[19]

12. Order No. 888 also clarified the Commission's interpretation of the federal/state jurisdictional boundaries over transmission and local distribution. While it reaffirmed that the Commission has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, it nevertheless recognized the legitimate concerns of state regulatory authorities regarding the transmission component of bundled retail sales. The Commission therefore declined to extend its unbundling requirement to the transmission component of bundled retail sales. On appeal, the U.S. Supreme Court affirmed this element of Order No. 888, finding that the Commission made a statutorily permissible choice.[20]

13. The same day it issued Order No. 888, the Commission issued a companion order, Order No. 889, addressing both the separation of vertically integrated utilities' transmission and merchant functions, the information transmission providers were required to make public and the electronic means they were required to use to do so. Order No. 889 imposed Standards of Conduct governing the separation of, and communications between, the utility's transmission and wholesale power functions, to prevent the utility from giving its merchant arm preferential access to transmission information. All public utilities that owned, controlled or operated facilities used in the transmission of electric energy in interstate commerce were required to create or participate in an Open Access Same-Time Information System (OASIS) that was to provide existing and potential transmission customers the same access to transmission information.

14. Among the information required to be posted by Order No. 889 was the transmission provider's calculation of ATC. Though the Commission acknowledged that before-the-fact measurement of the availability of transmission service is ''difficult,'' it concluded that it was important to give potential transmission customers ''an easy-to-understand indicator of service availability.'' [21] Because formal methods did not then exist to calculate ATC and total transfer capability (TTC), the Commission encouraged industry efforts to develop consistent methods for calculating ATC and TTC.[22] Order No. 889 ultimately required transmission providers to base their calculations on ''current industry practices, standards and criteria'' and to describe their methodology in their tariffs.[23] The Commission noted that the requirement that transmission providers purchase only ATC that is posted as available ''should create an adequate incentive for them to calculate ATC and TTC as accurately and as uniformly as possible.'' [24]

15. The electric industry continued to undergo economic and regulatory changes in the years following the issuance of Order No. 888. Retail access was adopted by approximately 25 states in the late 1990s.[25] This state restructuring activity spurred significant changes at the wholesale level as well by encouraging or requiring the divestiture of generation plants by traditional electric utilities and the development of ISOs that could manage short-term energy markets necessary to support retail access. At the same time, there was a significant increase in the number of mergers between traditional electric utilities and between electric utilities and gas pipeline companies, and large increases in the number of power marketers and independent generation facility developers entering the marketplace. Trade in bulk power markets increased significantly and the Nation's transmission grid was used more heavily and in new ways as customers took advantage of the *pro forma* OATT and purchased power from competitive sellers.

16. In the wake of these changes, in December 1999, the Commission adopted Order No. 2000.[26] That rulemaking recognized that Order No. 888 set the foundation upon which competitive electric markets could develop, but did not eliminate the potential to engage in undue discrimination and preference in the provision of transmission service.[27] The rulemaking also recognized that Order No. 888 did not address the regional nature of the grid, including the treatment of parallel flows, pancaked rates, and congestion management. Thus, the Commission encouraged the creation of RTOs to address important operational and reliability issues and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. The Commission found that RTOs would increase the efficiency of wholesale markets by eliminating pancaked rates, internalizing parallel flow, managing congestion efficiently and operating markets for energy, capacity and ancillary services. The Commission

[16] This is known as ''functional unbundling'' because the transmission element of a wholesale sale is separated or unbundled from the generation element of that sale, although the public utility may retain ownership over both functions. *See infra* Part IV.B.4.

[17] *See* Order No. 888 at 31,769–70 (noting that the *pro forma* OATT expressly identified certain non-rate terms and conditions, such as the time deadlines for determining available capability in section 18.4 or scheduling changes in sections 13.8 and 14.6, that may be modified to account for regional practices if such practices are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider).

[18] Order No. 888 at 31,655.

[19] *Id.* at 31,730–32.

[20] *New York* v. *FERC*, 535 U.S. 1 (2002).

[21] Order No. 889 at 31,605.

[22] *Id.* at 31,607.

[23] *Id.*

[24] *Id.*

[25] See Energy Information Administration, Retail Unbundling—U.S. Summary (2005), *http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/us.html.*

[26] *See supra* note 3.

[27] Order No. 2000 at 31,015.

established an open, collaborative process that relied on voluntary regional participation to design RTOs tailored to the specific needs of each region. The Commission noted, however, that ''[i]f the industry fails to form RTOs under this approach, the Commission will reconsider what further regulatory steps are in the public interest.'' [28]

17. Following Order No. 2000, RTOs were approved in several regions of the country including the Northeast (PJM Interconnection, Inc.; ISO New England), the Midwest (MISO) and the South (SPP). In most cases, RTOs have assumed responsibility for calculating ATC across the footprint of the RTO, as well as the planning and expansion of the transmission grid, at least for facilities necessary for maintaining system reliability. However, large areas of the Nation have not developed RTOs using the voluntary structure adopted by the Commission in Order No. 2000. Moreover, transmission customers have complained that even in RTO markets there are instances when comparable transmission service is not provided, particularly in the area of transmission planning.

C. EPAct 2005 and Recent Developments

18. EPAct 2005,[29] enacted on August 8, 2005, added a number of new authorities and priorities for the Commission and emphasized certain of its existing obligations. Specifically, EPAct 2005 recognized the importance of adequate transmission infrastructure development and its role in facilitating the development of competitive wholesale markets. For example, Congress required the Commission to adopt a rule establishing incentive ratemaking for transmission infrastructure to help promote reliability and reduce congestion.[30] Congress further directed the Commission to ''exercise its authority'' under EPAct 2005 ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities.'' [31] Congress also gave the Commission certain ''backstop'' transmission siting authority, and authorized the creation of interstate compacts establishing transmission siting agencies.[32] EPAct 2005 also authorized the Commission to require unregulated transmitting utilities (except for certain small entities) to provide access to their transmission facilities on a comparable basis.[33] Congress further ordered the Department of Energy (DOE) to study the benefits of economic dispatch and required the Commission to convene regional joint boards to develop a report to Congress containing recommendations for the use of security constrained economic dispatch within each region.[34] Congress also directed the Commission to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers, and it authorized the Commission to prescribe rules to provide for the dissemination of information about the availability and price of wholesale electric energy and transmission service.[35] Finally, Congress emphasized compliance with the Commission's regulations, increasing the civil and criminal penalties for violations of Commission-administered statutes and regulations.[36]

19. Recognizing the need for reform of Order No. 888 in light of these developments and those described in the next section, the Commission issued an NOI in September 2005 seeking comments on the reforms needed to the Order No. 888 *pro forma* OATT to prevent undue discrimination and preference in the provision of transmission services. In the NOI, the Commission expressed its preliminary view that reforms to the *pro forma* OATT and public utilities' OATTs are necessary to avoid undue discrimination or preference in the provision of transmission service. The NOI sought comments on how best to accomplish the Commission's goals, specifically with respect to enhancements that are needed to: (1) Remedy any unduly discriminatory or preferential application of the pro forma OATT or (2) improve the clarity of the Order No. 888 *pro forma* OATT and the individual public utility tariffs in order to more readily identify violations and facilitate compliance.

20. The Commission received over 4,000 pages of initial and reply comments on the NOI. Based on these comments, the comments submitted in response to the ATC NOI, our experience in implementing Order No. 888, and the changes in the industry since we adopted it, we conclude that reform of the *pro forma* OATT is necessary, for the reasons we discuss next.

III. The Need for Reform of Order No. 888

A. Opportunities for Undue Discrimination Continue To Exist

21. In Order No. 2000, the Commission found that ''opportunities for undue discrimination continue to exist that may not be remedied adequately by [the] functional unbundling [remedy of Order No. 888].'' [37] The Commission made a similar finding in Order No. 2003, holding that opportunities for undue discrimination continue to exist in areas where the *pro forma* OATT leaves transmission providers with substantial discretion.[38] The Commission has a responsibility under section 206 of the FPA to remedy undue discrimination.[39] Our action today proposes to fulfill that responsibility by proposing reforms to the *pro forma* OATT that will address remaining opportunities for undue discrimination.

22. As the Commission noted in Order No. 888, it is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves.[40] Such an incentive can lead to unduly discriminatory behavior

[28] *Id.* at 30, 993.

[29] *See supra* note 6.

[30] EPAct 2005 sec. 1241 (to be codified at section 219 of the FPA, 16 U.S.C. 824s).

[31] EPAct 2005 sec. 1233(a) (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q).

[32] EPAct 2005 sec. 1221(a) (to be codified at section 216 of the FPA, 16 U.S.C. 824p).

[33] EPAct 2005 sec. 1231 (to be codified at section 211A of the FPA, 16 U.S.C. 824j–1).

[34] EPAct 2005 sec. 1234 (to be codified at 42 U.S.C. 16432); EPAct 2005 sec. 1298 (to be codified at section 223 of the FPA, 16 U.S.C. 824w). EPAct 2005 defined economic dispatch as ''the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.'' EPAct 2005 sec. 1234 (b).

[35] EPAct 2005 sec. 1281 (to be codified at section 220 of the FPA, 16 U.S.C. 824t).

[36] EPAct 2005 sec. 1284(d) (to be codified at section 316 of the FPA, 16 U.S.C. 825o); EPAct 2005 sec. 1284(e) (to be codified at section 316A of the FPA, 16 U.S.C. 825o–1).

[37] Order No. 2000 at 31,105.

[38] Order No. 2003 at P 11–12.

[39] In *Associated Gas Distributors* v. *FERC,* 824 F.2d 981 (D.C. Cir. 1987), (*AGD*), the court concluded that, like the Natural Gas Act, the FPA ''fairly bristles'' with concern over undue discrimination. Based on *AGD*, the Commission determined in Order No. 888 that:

> The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. * * * *AGD* demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access as a remedy for undue discrimination.

Order No. 888 at 31,669.

[40] *Id.* at 31,682.

against third parties, particularly if public utilities have unnecessarily broad discretion in the application of their tariffs. This discretion also can create problems for transmission providers seeking to comply with our regulations in good faith because so many issues are left for their interpretation, thereby increasing the possibility of disputes with transmission customers and enforcement actions by the Commission.[41] Transmission customers also have found ways to use the tariffs to their own advantage, particularly in the scheduling and queuing processes.[42] Finally, tariff provisions have been modified in numerous ways on a company-by-company basis, leading to uncertainties within the industry as to the proper interpretation of those provisions and to unnecessarily inconsistent treatment of transmission customers across public utilities.

23. Commenters suggest that enhanced clarity and consistency in the *pro forma* OATT would go a long way toward eliminating the opportunities for undue discrimination and the perception that it is occurring.[43] Calpine notes that undue discrimination is most likely to occur when the transmission provider retains discretion to implement an OATT provision in a manner that favors its affiliated generation. APPA asserts that the success of the OATT regime depends on public utilities' ability to faithfully implement the OATT's provisions. Large transmission providers share this view to some degree. Entergy notes that a lack of clarity is at the heart of many disputes involving the OATT, and urges the Commission to improve the OATT in a manner that will minimize the potential for future violations. Duke posits that tariff terms and conditions that are susceptible to multiple interpretations present opportunities for discrimination and/or the perception thereof. Progress Energy agrees that several OATT provisions can be interpreted differently, leaving room for disagreement as to their meaning.

24. Perhaps the most obvious deficiency in this regard is ATC calculation. In Order Nos. 888 and 889, the Commission declined to require a specific methodology for ATC calculation. As a result, there are few clear rules respecting ATC calculation, and transmission providers, therefore, retain unnecessarily broad discretion in this area. On systems where transmission capacity is congested, this lack of consistency, coupled with a lack of transparency, has led to recurring disputes over whether the transmission provider is exercising its discretion to discriminate against its competitors.

25. There is a similar lack of clarity in the transmission provider's planning obligations. Order No. 888 included a general obligation on the part of the transmission providers to plan on a comparable basis (*i.e.*, comparable to the manner in which it would plan for its own needs) to serve network loads and to construct new facilities as necessary to respond to requests for firm service from point-to-point customers. However, there were no clear guidelines with respect to whether transmission customers should be included in the planning process, what standards and criteria should be used in system planning, and whether the planning process should identify potential economic upgrades that could benefit a wide range of customers, as opposed to responding only to customer-specific requests. Here too, this lack of clarity has led to significant disputes over whether transmission providers are planning on a nondiscriminatory basis or are favoring service to their own loads.

B. A Lack of Transparency Undermines Confidence in Open Access and Impedes Enforcement of Open Access Requirements

26. A major focus of comments on the NOI is that increased transparency would aid transmission customers in their participation in the wholesale market.[44] Constellation explains that the transmission provider's unique position as the owner and operator of the transmission system and often the majority of the generation assets in its control area gives it better information than its transmission customers. Moreover, the transmission provider, Constellation argues, has financial incentives to use the system differently, and more efficiently, to serve its own loads than to serve its other customers under the *pro forma* OATT. TDU Systems urges the Commission to ensure that transmission providers make their actions under the OATT completely transparent on a timely basis to all transmission customers. NARUC posits that enhanced reporting requirements, if sufficiently targeted, would facilitate greater transparency in transmission activities. Alberta Intervenors states that the current *pro forma* OATT provides transmission customers with only a narrow glimpse of how the system is being operated. For example, Bonneville notes that many terms and conditions of native load service are not transparent to OATT transmission customers.[45] EEI also states that greater transparency, such as with respect to ATC calculation, can increase confidence in open access and potentially reduce claims of undue discrimination.

27. Calpine argues that undue discrimination is difficult to detect given the lack of access to data, analytical assumptions, and processes used by transmission providers to determine transmission access and service. It recommends that the Commission increase reporting requirements for denials of transmission service, for congestion management mitigation events, including curtailments and redispatch, and for transmission expansion planning decisions. Powerex notes that the Commission already has posting standards, and urges the Commission to enforce them and to increase requirements to provide more meaningful posting of reliable ATC data, curtailment methodology and results, details relating to denials of service, and congestion information. Constellation agrees, urging the Commission to require OASIS posting of service metrics, such as all transmission requests approved, rejected, confirmed and curtailed.

28. A common theme in the comments is that the lack of transparency can lead to claims of undue discrimination and can make such claims more difficult to resolve.[46] As such, National Grid asserts that greater transparency will allow the Commission and transmission system users to understand when a transmission access decision is

[41] *See, e.g.*, Order No. 2003 at P 11–12.

[42] *See, e.g.*, Potomac Economics, Ltd., *2004 State of the Market Report: Midwest ISO* at 30–31, 34–35 (Jun. 2005) (explaining that the queuing process, by giving customers the opportunity to submit multiple requests for service, provides a low or no-cost option that restricts other customers' access to congested interfaces, and the scheduling process, by allowing customers to leave transmission requests unconfirmed, provides a free option that may invite hoarding or result in underutilized capacity), *http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-7bf20a48324a/2004%20MISO%20SOM%20Report.pdf?action=download&_property=Attachment.*

[43] *E.g.,* Calpine, Duke, and MidAmerican. (A list of commenter acronyms may be found in Appendix A). As the Commission noted in Order No. 2000, ''[p]erceptions of discrimination are significant impediments to competitive markets. Efficient and competitive markets will develop only if market participants have confidence that the system is administered fairly.'' Order No. 2000 at 31,017.

[44] *E.g.,* LG&E, MidAmerican, Midwest SATs, TDU Systems, and Williams.

[45] Bonneville urges the Commission to require load-serving transmission providers to post the same information for bundled retail load that they must post for service to network customers.

[46] *E.g.,* Ameren, National Grid, and NRECA.

motivated by a legitimate reason rather than an intent to discriminate. If transmission customers have more accurate information about the transmission service request process, National Grid contends, they also will have more accurate expectations and a better understanding of how to expedite the implementation of service. Though NRECA agrees that increased transparency will allow the Commission to deter undue discrimination and facilitate accountability, it urges the Commission to require not just raw data but meaningful, clear and understandable data, in a format that facilitates understanding.

29. Commenters urge the Commission to improve the transparency of transmission service in a number of areas, particularly the evaluation of ATC and the planning of the transmission system.[47] Another area often cited as lacking sufficient transparency is the processing of transmission service requests and studies. For example, several commenters note that system impact studies are often not completed within the tariff-prescribed time limits, and that information about that process is not available to transmission customers.[48] TDU Systems suggests that one way to address the difficulty of determining acceptable delays is to require transmission providers to post statistics on their OASIS sites providing information as to the length of time it might take to process requests for transmission service. Cinergy proposes that adopting such reporting metrics could result in an improved quality of service.

30. We agree that a lack of transparency both increases the potential for undue discrimination and makes it more difficult to detect. We believe this lack of sufficient transparency is caused in part by inadequate compliance with our existing OASIS regulations, and in part by inadequate transparency requirements. Our reforms address both elements of the problem in an effort to increase confidence in open access tariffs and to facilitate compliance with our regulations and our enforcement of them.

C. Congestion and Inadequate Infrastructure Development Impede Customers' Use of the Grid

31. The ability and incentive to discriminate increases as the transmission system becomes more congested. Vertically integrated utilities do not have an incentive to expand the grid to accommodate new entry or to facilitate the dispatch of more efficient competitors. Even with the advent of RTOs, transmission infrastructure development has not kept pace with the increase in demand for electricity. Transmission capacity is being constructed at a much slower rate than the rate of increase in customer demand. Indeed, transmission capacity per MW of peak demand declined at an average rate of 2.1 percent per year during the period 1992 to 2002.[49] Investment for the most recent year available, 2003, was below 1975 levels,[50] and projections suggest that this trend will continue through 2012.[51] As a result, there has been a significant decrease in transmission capacity relative to load in every NERC region.[52] EEI estimates that capital spending must increase by 25 percent, from $4 billion annually to $5 billion annually, to ensure system reliability and to accommodate wholesale electric markets.[53] The legacy systems constructed by vertically integrated utilities prior to the adoption of Order No. 888 support ''only limited amounts of inter-regional power flows and transactions. Thus, existing systems cannot fully support all of society's goals for a modern electric-power system.'' [54] These systems were built to meet the vertically integrated utilities' retail native load obligations, not to support the development of a bulk power market.

32. Inadequate expansion of the transmission grid has contributed to increasing transmission congestion in most regions of the country. Transmission congestion has created fairly small local load pockets in primarily urban areas, *e.g.*, New York City, Long Island, Boston, parts of Connecticut, and the San Francisco Bay Area. Other load pocket concerns have arisen in parts of northern Virginia, and various load centers in SPP. Still other constraints are more regional in scope: (1) From the Midwest to the Mid-Atlantic, (2) from the Midwest to the Tennessee Valley Authority (TVA), (3) into and within California, (4) from TVA and Southern into Entergy, (5) from Mid-America Interconnected Network into Wisconsin-Upper Michigan Systems, and (6) into Florida. The existence of these and other constraints affecting transmission systems can result in an increase in the frequency of denials of requests for transmission service, and an increase in the frequency of transmission service interruptions and/or curtailments of transmission service. While not all congestion needs to be remedied (*i.e.*, if the cost of the congestion is less than the cost to relieve it), it is also true that undue discrimination and preferential treatment also are much more difficult to detect when the transmission grid is constrained, given the lack of transparency in ATC calculations and transmission system planning. Increased congestion also presents additional opportunities for undue discrimination. As a result, it is more difficult for the Commission to carry out its statutory responsibility to ensure that transmission providers provide nondiscriminatory open access transmission service.

33. In recognition of the lack of adequate infrastructure, a broad cross-section of the industry supports greater coordination in the planning and investment in transmission infrastructure between transmission providers, transmission customers and state regulatory agencies. A major focus of comments on our NOI was the need to plan and build infrastructure to facilitate regional electricity markets. For example, AEP argues that the most important issue faced by public utilities and their customers is not day-to-day OATT administration but the planning and expansion of the transmission grid. EEI likewise asserts that the focus should be on the need to develop energy infrastructure necessary to facilitate growth in wholesale electric market transactions. Santa Clara acknowledges that lack of needed infrastructure causes the grid to become constrained and less reliable, which sometimes provides even stronger incentives for owners to restrict access by others. The Nevada Companies urge the Commission to focus on ways Order No. 888 and the *pro forma* OATT can be revised to eliminate disincentives to the construction of additional transmission facilities. Xcel suggests that the

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[47] We discuss these specific aspects of the *pro forma* OATT below in Parts V.A. and V.B.

[48] *E.g.*, Constellation, EPSA, Powerex, and Williams.

[49] Eric Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects* (Aug. 2004), available at *http://www.eei.org/industry_issues/energy_infrastructure/transmission/USTransCapacity10-18-04.pdf* (Present Status and Future Prospects).

[50] EEI, *EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures (1999–2008)* at 3 (May 2005), available at *http://www.eei.org/industry_issues/energy_infrastructure/transmission/Trans_Survey_Web.pdf.*

[51] Present Status and Future Prospects at v.

[52] Brendan Kirby (Oak Ridge National Laboratory, U.S. Department of Energy, *Barriers to Transmission Investment*, Technical Conference Presentation, (Docket No. AD05–5–000) (April 22, 2005) Transmission Independence and Investment.

[53] *Energy Policy Act of 2005: Hearings before the House Subcommittee on Energy and Commerce*, 109th Congress, First Sess. (2005) (Prepared statement of Thomas R. Kuhn, President of EEI).

[54] Present Status and Future Prospects at v.

Commission focus its efforts on ways to encourage investment in new energy infrastructure as a way of easing congestion and enabling growth in market transactions. Salt River contends that the Commission should increase incentives to participate in long-term regional planning processes. Midwest SATs argue that increased access for all transmission system users through policies that promote investment in transmission will do more to reduce undue discrimination than policies that seek to uncover and penalize such discrimination.

34. Customers also complain that there is often a lack of transparency in utility transmission planning processes, which the customers claim typically do not include economic system upgrades that would benefit non-affiliate users of the system. Customers also note the lack of clarity in the existing planning obligations required of transmission providers. They assert that these failures have contributed to the inadequate development of the transmission grid.

35. Order No. 888 contemplated that ISOs would enhance infrastructure development through open and regional planning processes, but these efforts have stalled in many regions of the country. Even where RTOs have been established, there have been concerns that the planning process has not always been sufficiently robust, inclusive or transparent to ensure that transmission investment occurs where it is reasonably needed for all users of the grid. For example, in its reply comments, TDU Systems urges the Commission to include RTOs in its planning reforms, contending that many RTO planning processes are not open to all stakeholders, nor are they collaborative and inclusive. Many commenters argue that RTO transmission planning regimes have failed to get needed transmission facilities built.[55]

36. We conclude that the inadequacy of the existing obligation to conduct joint and regional transmission system planning, coupled with the lack of transparency surrounding system planning generally, require reform of the *pro forma* OATT to ensure that transmission infrastructure is constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers.

D. A Consistent Method of Measuring ATC Has Not Been Established

37. Under Order No. 888, each public utility calculates the amount of transfer capability on its system that is available for sale to third parties.[56] However, Order No. 888 did not require that the methodology for ATC calculation be standardized across the industry, nor did it impose any specific requirements regarding the disclosure of the methodologies used by each transmission provider. As a result, there are a variety of ATC calculation methodologies in use today. Moreover, there is often very little transparency regarding the nature of these calculations, given that many transmission providers have filed only summary explanations of their ATC methodologies in Attachment C to the OATT. As a result, transmission providers retain unnecessarily broad discretion in calculating ATC. The resulting discretion is a significant problem because calculation of ATC, which varies greatly depending on the criteria and assumptions used, may allow the transmission provider to discriminate in subtle ways against its competitors. This discretion, coupled with the lack of transparency, also hampers the detection of undue discrimination and, thereby, undermines the Commission's ability to enforce the general requirement in Order No. 888 that transmission service be provided on a not unduly discriminatory basis.[57]

38. The comments on the NOI and the ATC NOI reflect these underlying problems. Many market participants complain that there is widespread misinformation regarding the actual ATC, which results in missed opportunities for transactions. ATC calculation errors often occur. A lack of transparency leaves transmission customers unaware of why some transmission requests are granted and others are denied.[58] Several ATC inputs, such as the capacity benefit margin (CBM) or the transmission reliability margin (TRM), can be calculated using overly conservative or otherwise faulty assumptions. Transmission customers often complain that transmission providers designate unreasonably high CBM or TRM levels, which limits the amount of remaining transfer capability available for other users of the system.

39. As a result of these uncertainties, the Commission issued the ATC NOI to address the lack of clear and consistent methodologies for calculating ATC. In the ATC NOI, the Commission acknowledged that NERC has been working on specific recommendations for calculating and coordinating ATC and available flowgate capability (AFC).[59] That NERC effort culminated in a report and a number of recommendations. The Commission asked for comments on those recommendations, as well as comments on whether there should be common transmission calculation methodologies among regions. The Commission has reviewed those comments as part of this proceeding.[60]

40. Many commenters support the development of a consistent, industry-wide methodology for calculating ATC.[61] These commenters maintain that a requirement that all transmission providers use the same methodology to determine ATC would not only remedy the lack of clarity that surrounds these calculations and reservations, but would provide regulatory certainty and assist transmission customers in predicting the outcome of transmission service requests.

41. We agree. Although the industry has sought to pursue greater consistency in ATC calculations through existing NERC processes, those efforts to date have been largely unsuccessful. The lack of a consistent, industry-wide methodology for calculating ATC gives transmission providers the ability and the opportunity to unduly discriminate against third parties. We therefore propose below a number of reforms to the process of calculating ATC to provide clarity and transparency to users of the grid.

E. A Number of Transmission Pricing Policies May Impede the Use of the Grid

42. Transmission customers often complain about the level and scope of imbalance charges that are levied under the *pro forma* OATT and under individual interconnection agreements.

[55] *E.g.,* APPA, TDU Systems Reply Comments, and Williams Reply Comments.

[56] Order No. 888 at 31,794 n.610.

[57] APPA submitted comments in Docket No. RM05–17–000 arguing that the calculation and posting of ATC ''sits at the pivot point among reliability, economic regulation and wholesale electric commerce.'' APPA at 5.

[58] *See, e.g.,* EEI at 18 (agreeing that the Commission should require transmission providers to make their ATC calculations more transparent).

[59] *See* NERC, *Long-Term AFC/ATC Task Force Final Report* (2005) (NERC Report) at 2, available at *ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf.*

[60] Accordingly, we consolidate Docket No. RM05–17–000 with this proceeding. We will distinguish the comments received in the ATC NOI proceeding by the designation ''ATC NOI Comments.'' In addition, we also revise the name of the proceeding in Docket No. RM05–17–000 to ''Preventing Undue Discrimination and Preference in Transmission Service.''

[61] *E.g.,* Alcoa, AWEA, Constellation, Exelon, Occidental, and Renewable Energy.

Energy imbalance charges, including penalties on some systems, are imposed on a transmission customer when the amount of energy scheduled for delivery to the transmission grid does not equal the amount of energy withdrawn by that customer. Customers complain that these charges are excessive and not related to the actual costs incurred by transmission providers. They also argue that the inconsistency between these charges in different control areas is unnecessary, and that other means of compensating the transmission provider, such as return-in-kind, should be considered. Generator imbalance charges are levied on generators for deviations between the amount of energy they schedule and the amount they actually deliver to the grid. Generators likewise complain that these charges are excessive, that transmission providers refuse to credit generators with the revenues resulting from imbalance penalties that are collected, and that transmission providers prevent unaffiliated generators from purchasing or self-supplying generator imbalance services. In addition, owners of intermittent resources complain that generator imbalance penalties, which are imposed to provide an incentive for generators to schedule accurately, are inappropriate given their lack of control and ability to cure deviations.

43. Transmission providers and customers raise a number of concerns related to the pricing of transmission service under Order No. 888, contending that the Commission's pricing policies are in need of reform. For example, under the *pro forma* OATT, network customers can receive a credit toward their transmission charges for new facilities that they jointly plan with the transmission provider. Customers contend that this provision actually acts as a disincentive for joint planning because transmission providers can avoid granting credits if they fail to jointly plan with their transmission customers.

44. Finally, there is also concern about the appropriate rate for transmission capacity that has been resold by the original transmission customer. Under Order No. 888, such capacity may be priced at the higher of the original rate, the transmission provider's maximum stated firm rate, or the assignor's opportunity costs capped at the cost of expansion. Customers complain that this policy does not work when opportunity costs exceed the embedded cost rate, because the assignor must make a FPA section 205 filing with the Commission that estimates its opportunity cost over the term of the reassignment as well as the cost of system expansion. The time and effort required to complete the regulatory process appears to inhibit such reassignments.

45. Although Order No. 888 was primarily directed at establishing the non-rate terms and conditions of open access, the rule did adopt certain pricing policies that were associated with the form of open access being ordered. After reviewing the comments, we believe certain reforms are appropriate because some of the pricing policies associated with the *pro forma* OATT are no longer just and reasonable or are otherwise unduly discriminatory. However, we do not intend to pursue generic reform of other pricing policies that are better addressed on a region-or case-specific basis, such as the pricing of new transmission facilities.

F. EPAct 2005 Emphasized Certain Policies and Priorities for the Commission

46. The reforms we propose today also are consistent with the policies and priorities embodied in EPAct 2005, in which Congress emphasized many of the principles reflected in this NOPR.

47. First, Congress in EPAct 2005 placed special emphasis on the development of transmission infrastructure. Congress required the Commission to adopt a rule establishing incentive-based rates for new transmission infrastructure investment. The stated purpose of new FPA section 219 is to benefit ''consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.'' [62] FPA section 219 requires the Commission to ''promot[e] capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities.'' [63] Congress also gave the Commission certain ''backstop'' transmission siting authority, and authorized the creation of interstate compacts establishing transmission siting agencies.[64] Finally, the Commission was directed to ''exercise its authority'' under EPAct 2005 ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights* * * on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.'' [65] Although these provisions are, or will be, addressed primarily in other proceedings, our NOPR is consistent with these provisions because it supports new infrastructure by reforming the transmission planning process to ensure that it is open, transparent and nondiscriminatory.[66]

48. Second, Congress emphasized the need for greater transparency in electricity markets, including transmission service. EPAct 2005 added section 220 to the FPA, which requires the Commission to facilitate ''price transparency in markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of [that market], fair competition, and the protection of consumers.'' [67] The Commission was authorized to ''prescribe such rules as the Commission determines necessary and appropriate to carry out the purposes of'' FPA section 220. Those rules ''shall provide for the dissemination, on a timely basis, of information about the availability and prices of wholesale electric energy and transmission service to the Commission, State commissions, buyers and sellers of wholesale electric energy, users of transmission services, and the public.'' Our NOPR similarly seeks to promote greater transparency in the provision of transmission service in many important areas, including ATC calculation and transmission planning.

49. Finally, Congress emphasized compliance with the Commission's regulations, increasing the civil and criminal penalties for violations of Commission-administered statutes and regulations.[68] This new authority buttresses the Commission's efforts to enforce public utility OATTs and the regulations requiring transmission information to be posted on OASIS. As we explained in the Enforcement Policy Statement, however, this new authority carries with it the responsibility to ensure that enforcement is firm but fair and that our rules are as clear as

[62] EPAct 2005 sec. 1241 (to be codified at section 219 of the FPA, 16 U.S.C. 824s). The Commission issued a NOPR implementing such an incentive rate program in November 2005. *See Promoting Transmission Investment through Pricing Reform*, 70 FR 71409 (Nov. 29, 2005), FERC Stats. & Regs. ¶ 32,593 (2005).

[63] FPA Sec. 219(b)(1).

[64] EPAct 2005 sec. 1221(a) (to be codified at section 216 of the FPA, 16 U.S.C. 824p).

[65] EPAct 2005 sec. 1233(a) (to be codified at section. 217(b)(4) of the FPA, 16 U.S.C. 824q).

[66] We note that we also have proposed to implement FPA section 217(b)(4) in a separate rulemaking in Docket No. RM06–8–000.

[67] EPAct 2005 sec. 1281 (to be codified at 16 U.S.C. 824t).

[68] EPAct 2005 sec. 1284(e)(1) (to be codified at section 316(A) of the FPA, 16 U.S.C. 825o–1 (2000).

practicable to facilitate compliance.[69] The NOPR is fully consistent with these principles because it seeks, in many areas, to clarify our rules to facilitate compliance by transmission providers.

IV. Summary, Scope and Applicability of the Proposed Rule

50. This section provides: (1) A summary of the major components of the NOPR, (2) a description of the core elements of Order No. 888 that we propose to retain, and (3) a discussion of the applicability of the proposed rule to various entities.

A. Summary of Proposed Reforms

51. *Consistency and transparency of ATC calculations.* The Commission finds that the lack of a consistent, industry-wide methodology for calculating ATC, and the lack of adequate transparency in ATC calculations, increases the potential for undue discrimination and also makes undue discrimination more difficult to detect. The lack of consistent standards can facilitate undue discrimination by giving a transmission provider the discretion, and hence the ability and opportunity, to favor itself and its affiliates over third parties in how it calculates and allocates ATC and, therefore, may be unjust, unreasonable, unduly discriminatory and preferential. As a result, we propose to give the industry specific guidance and a firm deadline to develop certain requirements to make the process of calculating ATC and the process of exchanging data between transmission providers about ATC more consistent. In addition, we propose to amend *pro forma* OATT requirements as well as our OASIS regulations to increase the transparency in how ATC is calculated.

52. *Requirement for coordinated, open and transparent transmission planning.* The Commission finds that Order No. 888 does not contain sufficient protections to guard against undue discrimination in transmission system planning. This, in turn, can affect a customer's ability to obtain transmission service and the price it pays for transmission. Specifically, Order No. 888 does not require sufficient coordination, openness, and transparency in transmission planning to ensure that new infrastructure is constructed to meet the needs of all eligible customers on a not unduly discriminatory basis. Without adequate coordination and open participation, market participants have minimal input or insight into whether a particular transmission plan treats all loads and generators comparably. To ensure that truly comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we propose to amend the *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a sub-regional and regional level. To implement this remedy, we propose eight planning principles that each public utility transmission provider will be required to follow. We recognize that many regions have made significant progress in recent years in creating greater openness and transparency in transmission planning and believe our proposed reforms will build upon, strengthen, and improve this progress to reform transmission planning.

53. *Transmission Pricing Reforms.* Consistent with the focus of Order No. 888 on the non-rate terms and conditions of open access, the Commission does not intend to initiate broad reform of transmission pricing policy through this NOPR. However, we have identified several pricing rules that are part and parcel of OATT service that merit reform.

- *Energy and Generator Imbalance Charges.* We find that existing energy and generator imbalance charges may be excessive and otherwise unrelated to the cost of providing the service and, therefore, propose to reform energy and generator imbalance pricing. We propose to require that all such imbalance charges meet the following criteria: The charges must (1) be related to the cost of correcting the imbalance, (2) be tailored to encourage accurate scheduling behavior, such as by increasing the percentage of the adder as the deviations become larger, and (3) account for the special circumstances presented by intermittent generators, such as by waiving the higher ends of the deviation penalties.
- *Capacity Reassignment Pricing.* We find that the existing cap on the reassignment of point-to-point service may no longer be just and reasonable and, therefore, propose to eliminate the cap. We believe that removing the cap will eliminate an unnecessary impediment to the resale of capacity, which in turn should increase utilization of the grid and otherwise ensure that point-to-point service is just, reasonable and not unduly discriminatory. We seek comment on this proposal and, in particular, the nature of the reporting obligations that should be imposed as part of lifting the cap on reassignment.
- *Crediting of Customer-Owned Facilities.* We propose to retain most elements of our existing policy respecting the crediting of customer-owned facilities, including the requirement that such facilities meet the integration standard. However, we propose to eliminate the requirement that new facilities can receive credits only if they are ''jointly planned'' because this requirement may provide a disincentive to coordinated planning. Rather, we propose that such new facilities be eligible for credits if: (1) Such facilities are integrated into the operations of the transmission provider's facilities, and (2) such facilities would be eligible for inclusion in the transmission provider's annual transmission revenue requirement if owned by the transmission provider.

54. *Improvements to Point-to-Point Service.* The Commission concludes that the existing methods for evaluating requests for long-term firm point-to-point service may no longer be just, reasonable and not unduly discriminatory. When a transmission provider considers a new resource to serve native load, the transmission provider does not eliminate an otherwise economic option because the resource may not be deliverable in a few hours of the year. For transmission customers, however, the transmission provider evaluates whether service can be granted in every hour of the year that is modeled and, if not, it informs the customer that service cannot be provided out of existing transfer capability. Only if the transmission customer agrees to pay for time-consuming and costly facilities studies does the transmission provider evaluate redispatch options, including whether they are less expensive than the upgrade options. The Commission proposes to address this problem by clarifying that a transmission provider must use all of its available redispatch options to satisfy a request for firm point-to-point service and, at the transmission customer's option, these redispatch options must be studied before the customer is obligated to incur the costs and time delays associated with a facilities study. The Commission also seeks comment on whether this remedy is adequate or, alternatively, whether the Commission should modify the nature of point-to-point service to require that transmission providers offer a ''conditional firm'' service that would be subject to curtailment prior to firm service only a limited number of hours of the year.

55. *Reform of rollover rights.* The Commission concludes that section 2.2 of the *pro forma* OATT, which grants an

[69] *Enforcement of Statutes, Orders, Rules and Regulations,* Policy Statement on Enforcement, 113 FERC ¶ 61,068 (2005) (Enforcement Policy Statement).

ongoing right to transmission customers to renew or ''rollover'' their contracts, is in need of reform. The Commission proposes to revise that provision to apply to contracts that have a minimum term of five years, rather than the current minimum term of one year. We conclude that this reform will ensure that the rollover right is enjoyed by transmission customers that have made a significant commitment to (and investment in) the transmission grid. In addition, the Commission proposes that a transmission customer eligible for rollover rights must provide notice of whether or not it will exercise its right of first refusal to renew the contract no less than one year prior to the expiration date of the transmission service agreement, rather than within the current 60-day period.

56. *Increases in transparency to lessen the opportunities to discriminate and reduce transaction costs.* In addition to the increased transparency we propose to require regarding the calculation of ATC and transmission planning, we propose to increase the transparency of transmission service provided under the *pro forma* OATT in several other respects. For example, we propose to require transmission providers and their network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of an existing network resource. In addition, we propose to require the transmission provider to modify its OASIS so that requests to designate and terminate a network resource can be queried. We also propose to require the transmission provider to post on its OASIS a list of its current designated network resources and all network customers' current designated network resources. Finally, we propose to require transmission providers to post on OASIS all their business rules, practices and standards that relate to transmission services provided under the *pro forma* OATT.

57. *Strengthening enforcement of the pro forma OATT.* Our proposed reforms include several clarifications of the terms and conditions of the *pro forma* OATT that have made undue discrimination difficult to detect and otherwise frustrated enforcement of the obligation to provide open access, non-discriminatory transmission service. Our new civil penalty authority under EPAct 2005 gives us ample power to remedy tariff violations, but it also places upon us an increased responsibility to make the rules as clear as possible. In addition, we propose a number of posting and reporting requirements that will provide the Commission and market participants with information about each transmission provider's performance of *pro forma* OATT obligations. For example, we propose to require transmission providers to post specific performance metrics related to their completion of studies required under the *pro forma* OATT. We note that the Commission will continue to audit compliance with the *pro forma* OATT, and toward that end propose to require transmission information kept on OASIS to be retained for audit purposes for five years. Finally, we make a number of proposals relating to operational penalties assessed under the *pro forma* OATT, including so-called ''over-use'' penalties, and the treatment of operational penalty revenues collected from transmission providers and their affiliates.

58. Miscellaneous OATT improvements. We propose a number of improvements to the terms and conditions of the *pro forma* OATT to incorporate the lessons learned over the past ten years. We briefly note these below:

Hourly Firm. We propose to require transmission providers to offer hourly firm service under the *pro forma* OATT.

Designation of network resources. We propose to make a number of clarifications related to the types of agreements that may be designated as network resources, the process for verifying whether agreements meet the requirements in the *pro forma* OATT, and the requirement for transmission providers to designate and undesignate network resources. We also propose to require customers to submit an attestation with each application to designate a new network resource.

Reservation priorities. We propose to change the priority rules to give priority to pre-confirmed transmission service requests submitted in the same time period. We also propose to add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service.

Clarifications related to network service. We propose to clarify that a network customer may not use secondary network service to bring energy onto its system to support an off-system sale if the purchased power does not displace the customer's own higher cost generation. We also propose clarifications related to use of network service on an ''as available basis'' and to ''redirects'' of network service.

Definitions. In addition to some minor revisions, we propose to add a definition of ''non-firm sales'' to the *pro forma* OATT and propose to amend the definition of Good Utility Practice to reference the definition of ''reliable operation'' adopted in EPAct 2005.

B. Core Elements of Order No. 888 That Are Retained

59. Although we are proposing many important reforms to Order No. 888 and the *pro forma* OATT, we also wish to emphasize that we propose to retain many of the core elements of Order No. 888. We note that many of these core elements enjoy broad support across many sectors of the industry. In their comments, APPA, EEI, and NARUC urge the Commission to proceed carefully in reforming Order No. 888, focusing on incremental reforms not industry restructuring. We share the view that Order No. 888 can be strengthened without discarding its fundamental structure. We discuss below the core elements that are being retained and, where appropriate, respond to the comments on these points that were received in the NOI.

1. Federal/State Jurisdiction

60. In Order No. 888, the Commission stated that it has exclusive jurisdiction over the rates, terms and conditions of unbundled retail transmission in interstate commerce.[70] Though the Commission adopted a test for determining which facilities were used for retail transmission, as opposed to local distribution to end-users,[71] the Commission stated that it generally would defer to determinations by state regulatory authorities concerning where to draw the jurisdictional line under that test.[72] The Commission declined to assert jurisdiction over bundled retail transmission, reasoning that ''when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail.'' [73] The U.S. Supreme Court affirmed the Commission's decision to assert jurisdiction over unbundled but not bundled retail transmission, finding that the Commission made a statutorily permissible choice.[74]

61. We propose to retain the jurisdictional divide we established in Order No. 888. We also are mindful of the need for heightened cooperation between federal and state regulators in areas where there are overlapping federal and state policy concerns. Moreover, our jurisdictional determination was sustained by the U.S.

[70] Order No. 888 at 31,781.

[71] *Id.* at 31,771 (setting forth the seven-factor test).

[72] *Id.* at 31,781.

[73] *Id.*

[74] *See New York* v. *FERC,* 535 U.S. 1, 28 (2002).

Supreme Court and has been accepted by industry and state regulatory authorities. We see no reason to disturb that determination now.

2. Native Load Protection

62. Order No. 888 did not require transmission providers to unbundle transmission service to their retail native load nor did it require that bundled retail service be taken under the terms of the *pro forma* OATT.[75] Moreover, the Commission allowed a transmission provider to reserve, in its calculation of ATC, transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon.[76] As noted above, Order No. 888 granted a rollover right to existing firm service customers,[77] but allowed transmission providers to restrict that rollover right if the capacity was reasonably forecasted to be needed to serve native load customers, as long as that restriction was specified in the customer's service contract.[78]

63. Congress in section 1233 of EPAct 2005 added section 217 to the FPA, entitled ''Native Load Service Obligation,'' which addresses transmission rights held by load-serving entities. It allows load-serving entities to use their own and contracted-for transmission capacity to the extent required to meet their service obligations, without being subject to charges of unlawful discrimination. Among other things, FPA section 217 states that it does not require the abrogation of any contract or service agreement for firm transmission service or rights in effect as of the date of enactment.[79]

64. In the NOI, the Commission stated that it was not proposing to change the protection of native load embodied in Order No. 888.[80] The Commission sought comment on whether the approach the Commission took in Order No. 888 is the same as that set forth in FPA section 217.

Comments

65. Several commenters argue that the approach the Commission took in Order No. 888 is largely consistent with the treatment of native load preference in FPA section 217.[81] They state that Order No. 888 makes clear that native load has a priority right to a transmission providers' capacity and that transmission providers may reserve a portion of their capacity for native load growth.

66. Other commenters perceive varying degrees of difference between Order No. 888 and FPA section 217.[82] EEI states that FPA section 217 extends native load protection to all load-serving entities that have direct or indirect service obligations to end-users for terms of one year or more, while Order No. 888 does not. Nevada Companies and TAPS argue that the FPA section 217 requirement that the Commission exercise its authority to facilitate the planning and expansion of transmission facilities to satisfy the service obligations of load-serving entities necessitates changes to Order No. 888.

67. Several commenters argue that FPA section 217 requires the Commission to revisit its rollover rights policy.[83] Duke maintains that the current Commission approach is not the same as set forth in either Order No. 888 or FPA section 217 because the Commission's current approach to rollover rights does not meaningfully recognize the native load preference. Commission decisions since Order No. 888, according to Duke, have weakened the native load preference envisioned in Order No. 888 to the point where the Commission's treatment of the native load preference is not what Congress provides in FPA section 217. LPPC argues that FPA section 217 reverses Commission precedent that makes it impossible to recall capacity for native load once it is subject to a rollover right.

68. EEI states that in order to harmonize Order No. 888 rollover rights with the native load protections contained in FPA section 217, the Commission should revise the *pro forma* OATT to require a notice period for rollover rights that is consistent with the time needed to plan for and construct transmission facilities to serve native load customers and the rollover customer. EEI and Salt River argue that FPA section 217 requires that the Commission permit load-serving entities to implement curtailment procedures that recognize native load service priorities.

69. Metropolitan Water District argues that the mandate to preserve native load preference is complicated further when a transmission owner has transferred operational control to an ISO or RTO. In such a scenario, to honor the native load preference in FPA section 217, Metropolitan Water District contends that the Commission either should reconsider its prior rulings rejecting the allocation of physical rights to serve native load or should require ISOs and RTOs to issue financial rights options, in addition to financial right obligations, so that load-serving entities have a greater ability to avoid congestion costs in serving their native load.

Discussion

70. The Commission concludes that the protection of native load embodied in Order No. 888 is consistent with FPA section 217, and we reaffirm our commitment to the protection of native load. Order No. 888 gave public utilities the right to reserve existing transmission capacity needed for native load growth reasonably forecasted within the utility's current planning horizon. It also allowed transmission providers to restrict rollover rights based on a reasonably forecasted need at the time the contract is executed. This approach is consistent with FPA section 217, which protects the transmission rights of entities with service obligations to end-users or a distribution utility, to the extent required to meet their service obligations. Though commenters appear to believe FPA section 217 would support the cancellation of contracts that include rollover rights, FPA section 217 by its terms does not contemplate abrogation of existing transmission service contracts.[84] However, to the extent commenters argue that the terms of service and notice periods associated with the OATT rollover rights are too short to protect native load adequately, we note that we are proposing to extend them in this NOPR.

71. In response to Metropolitan Water District, the Commission finds that the issue of firm transmission rights in organized markets is best addressed as part of the long-term firm transmission rights rulemaking in Docket Nos. RM06–8–000 and AD05–7–000. We further note, in response to the comments of Nevada Companies and TAPS, that we are proposing a coordinated and regional planning process to facilitate the planning and expansion of transmission facilities pursuant to FPA section 217.

3. The Types of Transmission Services Offered

72. In Order No. 888, the Commission required all public utilities to offer on a non-discriminatory, open-access basis firm network service and firm and non-

[75] Order No. 888 at 31,745.

[76] *Id.* at 31,694.

[77] *Id.*; *pro forma* OATT section 2.2.

[78] Order No. 888–A at 30,198.

[79] 16 U.S.C. 217(f).

[80] NOI at P 9.

[81] *E.g.*, Memphis Light, Newmont Mining Reply Comments, Progress Energy, and TDU Systems.

[82] *E.g.*, Duke, EEI, Metropolitan Water District, and Southern.

[83] *E.g.*, Duke, Energy, LPPC, Progress Energy, Salt River, Santee Cooper, and Southern.

[84] *See* FPA section 217(f) (explaining that section 217 does not abrogate any firm service agreements or rights in effect as of the date of enactment).

firm point-to-point service. In the NOI, the Commission sought comments on whether the Commission should require transmission providers to offer transmission services in addition to, or in place of, the point-to-point and network services prescribed in the OATT.

73. Among other questions, the Commission asked whether network service alone or both network and point-to-point services should be converted into a single contract demand service.[85] Generally speaking, contract demand service is a hybrid of point-to-point and network services that is reservation-based and allows transmission customers to receive a firm entitlement to integrate multiple resources and deliver energy to multiple points, without paying a separate charge for each point of receipt or delivery. Contract demand service would allow current point-to-point customers to avoid having to arrange and pay for separate reservations for each point of receipt. And current network customers would be allowed to pay for transmission based on the amount of their reservation rather than customer loads at a delivery point.

Comments

74. Most commenters argue against requiring that network service alone or in combination with point-to-point service be converted into contract demand service.[86] Some warn that the imposition of this service would interfere with efficient transmission system planning and operation due to increased capacity reservations that would go unused.[87] They also argue that it would result in significant cost shifts among transmission customers if not priced correctly. FP&L argues that the current services are a better match for the actual use of the transmission system and thereby permit more ATC to be available.

75. Some commenters ask that the Commission require transmission providers to offer contract demand service as an additional transmission service option in the *pro forma* OATT.[88] AMP-Ohio argues that, as long as Commission policy requires network customers to pay load-ratio network transmission charges for load served with behind-the-meter generation, contract demand network service is essential to avoid unduly discriminatory transmission charges. Midwest Municipals and FMPA argue that the Commission should order contract demand service where the transmission provider does not plan and operate its system to meet total customer load because, as the Commission stated in Order No. 888, full network service is essential for achieving comparability and efficient integration of power supply and load. FMPA contends that where a customer needs network service from another system for only part of its load, it would benefit from being able to buy system power from multiple designated resources for part of its load. In this way, FMPA continues, the transmission provider would not have the planning obligation for the customer's entire load, perhaps avoiding or delaying expensive transmission additions. FMPA claims that such service would tend to benefit all transmission users because it would allow a more efficient use of the grid and provide additional transmission revenues.

76. Other commenters state that transmission providers should have the option whether to offer contract demand or other customized transmission services.[89] LPPC argues that the Commission should allow a transmission provider to voluntarily provide alternative forms of transmission service where circumstances support their implementation, with the caveat that such service must not place any market participant at a disadvantage or increase transmission rates for network or point-to-point customers. Southern proposes that the *pro forma* OATT be modified to include a process through which a transmission provider may propose to adopt new services that customers specifically request.

77. Commenters also raise general concerns regarding the use and potential abuse of network contract demand service. For example, MidAmerican argues that contract demand service should not be used as a means for transmission customers with behind-the-meter generation to avoid paying for a load-ratio share of a system that was built to support their entire load and on which they rely for service. Rather, MidAmerican continues, network contract demand service should be limited to situations in which deliverability is physically limited, such as where the integrated transmission system does not have the capacity to serve all the load at a designated point of delivery. EEI argues that the Commission should not convert network service to network contract demand service because conversion would result in a substantial reduction in ATC as it would provide contract rights on the transmission system on an around-the-clock basis that are equal to network load's monthly or annual peak loads.

Discussion

78. We propose to retain the services we ordered in Order No. 888: firm and non-firm point-to-point service and firm network service. We do not propose requiring transmission providers to adopt a network contract demand service, either as a replacement for network or point-to-point service or as a third category of service under the OATT. The Commission continues to believe that network and point-to-point services are the appropriate base-line service offerings in the OATT. Although forms of contract demand service have been approved by the Commission, and the service may provide benefits to certain customers, sufficient potential drawbacks exist that prevent us from concluding that it is a necessary transmission service that should be included in the *pro forma* OATT. For example, the service would require a departure from full load-ratio pricing for network customers, which may not be warranted to the extent the transmission provider plans its system to serve all native load. While the Commission concludes that it will not require all transmission providers to offer this service, we acknowledge that the introduction of this service on a voluntary basis may be appropriate in certain circumstances.

79. Although we are not proposing to require that transmission providers adopt contract demand service, we note that the commenters who support this service appear concerned principally with inequities in the pricing of network integration service. The Commission is addressing certain of these concerns elsewhere in the NOPR. For example, in this NOPR, we propose to modify our treatment of transmission credits for new transmission facilities and clarify that the transmission provider must satisfy the comparability requirement when including transmission facilities in its rate base for *pro forma* OATT purposes. We also address concerns regarding the linkage between how the transmission provider plans and

[85] For examples of contract demand service, the Commission cited *Florida Power Corp.*, FERC ¶ 61,248 (1995); *Wisconsin Electric Power Co.*, 72 FERC ¶ 61,033 (1995); and *Florida Power Corp.*, 81 FERC ¶ 61,247 (1997).

[86] *E.g.*, Ameren, APPA, Bonneville, Calpine, EEI, EPSA, Fallon Reply Comments, FP&L, NRECA, PacifiCorp, Southern, Suez Energy NA, TVA, TAPS, and TDU Systems.

[87] *E.g.*, EEI, FP&L, KCP&L, and TVA.

[88] *E.g.*, AMP-Ohio, APPA, Cogeneration Association of California Reply Comments, Constellation, EPSA, FMPA Reply Comments, Midwest Municipals, PacifiCorp, and Public Power Council.

[89] *E.g.*, LPPC, NRECA, and Southern.

operates its system through proposed revisions to planning and ATC.

4. Functional Unbundling

80. When the Commission proposed the open access policy that culminated in Order No. 888, there was considerable debate about whether corporate unbundling (in which a public utility's transmission and generation assets would be placed in separate corporate entities) was necessary to ensure non-discriminatory open access transmission service. The Commission decided to mandate functional, rather than corporate, unbundling of transmission and generation services. In Order No. 888, the Commission explained that functional unbundling has three components:

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

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

3. A public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.[90]

81. In the years following Order No. 888, a number of public utilities nonetheless underwent corporate unbundling. Many of these entities did so as a result of state-mandated restructuring laws. Others did so for corporate or tax reasons. Some entities divested all of their generation assets to a non-affiliate, while others simply restructured internally to place the generation assets in a different corporate subsidiary than the transmission assets. There remain, however, a significant number of vertically-integrated public utilities that have operated under the functional unbundling approach.

Comments

82. Retention of Order No. 888's functional unbundling approach is supported by a number of commenters. For example, the LPPC states that vertical integration remains a viable business model for serving customers reliably and at economic rates. LG&E posits that, absent a proven and real level of abuse, major structural changes are unwarranted. NARUC argues that the issue of whether there should be structural separation of generation from transmission is best left to the states. NPPD alleges that mandatory vertical unbundling would do more harm than good by threatening the continued economic operation of those utilities that continue to provide bundled service to their retail native load customers. The North Carolina Commission does not believe the evidence in that state supports the imposition of structural remedies.

83. Some commenters, however, continue to urge the Commission to impose structural separation. National Grid contends that the best way to eliminate the possibility of undue discrimination is to separate the ownership and operation of the transmission system from interests in the market. Calpine urges the Commission to structurally separate the merchant function that is engaged in selling power for resale from those who control access to transfer capability and service, not just those who operate the transmission system. TAPS argues that structural solutions are preferable to behavioral rules.

84. Many commenters favoring structural separation urge the Commission to impose an independent transmission coordinator requirement. These commenters would have transmission providers employ an independent entity to administer their OATTs, performing such functions as maintaining the utility's OASIS, granting or denying service requests, reviewing system impact and facilities study results, and overseeing decisions with respect to line ratings, transmission outages and generation dispatch.[91] Other commenters oppose the imposition of a potentially costly new layer of bureaucracy, at least on a generic basis.[92]

Discussion

85. We propose to preserve the functional unbundling approach adopted by Order No. 888. For public utilities that kept transmission and generation assets in the same corporate entity, the Commission imposed strict Standards of Conduct that required separation of the utilities' transmission system operations and wholesale marketing functions.[93] These Standards of Conduct were replaced by a broader set of rules adopted in Order No. 2004.[94] These rules require that employees engaged in transmission functions operate separately from employees of energy affiliates and marketing affiliates. A number of information sharing restrictions also apply, which prohibit transmission providers from allowing employees of their energy and marketing affiliates to obtain access to transmission or customer information, except via OASIS.

86. The Commission aggressively enforces the Standards of Conduct. The Commission's Office of Enforcement is well-suited to investigate potential violations of the Standards of Conduct and to propose remedies, including structural remedies if necessary, to ensure that the separation of function and information restrictions in Order No. 2004 are implemented.

87. The Commission has resolved a number of complaints related to the Standards of Conduct and the accompanying OASIS posting requirements.[95] In Order No. 888, the Commission noted that the possibility of filing a complaint under FPA section 206 is an additional safeguard if a public utility seeks to circumvent the functional unbundling requirement. The Commission's Enforcement Hotline likewise is available to customers that do not wish to file a formal complaint.

88. In addition, one of the criticisms of the functional unbundling requirement is that Order No. 888 leaves vertically integrated utilities with too much discretion in applying the OATT and gives them an incentive to use this discretion to their advantage. We agree that the existing *pro forma* OATT provides too much discretion in certain important areas. It is for this reason—as explained elsewhere in the NOPR—that we are proposing to require greater clarity and transparency in several areas of OATT administration. We believe these reforms will limit the discretion of transmission providers and make any remaining attempts to discriminate much easier to detect.

89. We believe that this increased clarity and transparency, when coupled with the Standards of Conduct and a rigorous enforcement program, will ensure that the functional unbundling requirement will serve its original purpose. As a result, just as the Commission concluded in Order No.

[90] Order No. 888 at 31,654.

[91] *E.g.,* Arkansas Commission, Calpine, Constellation, EPSA, and PPL.

[92] *E.g.,* APPA, NRECA, and TAPS.

[93] Order No. 889 at 31,595.

[94] *See Standards of Conduct for Transmission Providers,* Order No. 2004, 68 FR 69134 (Dec. 11, 2003), FERC Stats. & Regs. ¶ 31,155 (2003), *order on reh'g,* Order No. 2004–A, 69 FR 23562 (Apr. 29, 2004), FERC Stats. & Regs. ¶ 31,161 (2004), *order on reh'g,* Order No. 2004–B, 69 FR 28371 (Aug. 10, 2004), FERC Stats. & Regs. ¶31,166 (2004), *order on reh'g,* Order No. 2004–C, 70 FR 284 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,172 (2005), *order on reh'g,* Order No. 2004–D, 110 FERC ¶ 61,320 (2005), *appeal docketed sub nom. National Gas Fuel Supply Corporation* v. *FERC,* No. 04–1183 (D.C. Cir. June 9, 2004), codified at 18 CFR Part 358 (2005).

[95] *See Aquila Energy Marketing Corp.* v. *Niagara Mohawk Power Corp.,* 87 FERC ¶ 61,328 (1999)(finding that off-OASIS communicagtion between utilty and its marketing affiliate led to preferential treatment of the affiliate).

888 that more intrusive and costly corporate unbundling was not necessary, the Commission again concludes that there is no need to impose a corporate or structural unbundling requirement at this time. We believe that the *pro forma* OATT, if properly clarified and enforced, will enable us to eliminate the opportunity for undue discrimination in the provision of transmission service.

90. For the same reasons, we also decline to mandate an independent transmission coordinator for all transmission providers. We have concluded that such entities may be appropriate in certain circumstances and we support voluntary efforts to rely on them.[96] We do not agree, however, that there is sufficient basis for requiring them as a generic remedy for undue discrimination.

91. Our proposal to retain the functional unbundling approach of Order No. 888 does not suggest, however, a lack of support for structural changes that may be undertaken on a voluntary basis by each region, such as transmission-only companies, RTOs, or other reforms. We continue to support such efforts as potentially providing significant benefits in several areas, including, but not limited to, increased infrastructure investment and addressing regional issues such as cost recovery, pancaked rates, loop flow, and congestion management. At this time, we believe such efforts are best developed on a voluntary basis.

C. Applicability of the Proposed Rule

1. Public Utility Transmission Providers

92. Pursuant to its authority under FPA sections 205 and 206, the Commission in Order No. 888 required all public utilities that owned, controlled, or operated facilities used for transmitting electric energy in interstate commerce to file open access transmission tariffs that contained minimum terms and conditions of non-discriminatory service. The Commission recognized, however, that there may be circumstances in which a public utility believes that the *pro forma* OATT does not provide sufficient flexibility.[97] In addition, the Commission acknowledged that a public utility might be willing to offer superior non-rate terms and conditions. As a result, the Commission allowed a transmission provider to justify variations from the non-price terms and conditions of the *pro forma* OATT under two circumstances. First, certain provisions of Order No. 888 specifically allowed public utilities to use alternatives that were justified by ''regional differences.'' When submitting those provisions, public utilities were permitted to follow regional practices when doing so was ''reasonable, generally accepted in the region, and consistently adhered to by the transmission provider,''[98] as long as the utilities identified the regional practices in their compliance filings. Second, in subsequent FPA section 205 proceedings, public utilities were permitted to propose changes to any *pro forma* OATT provision that were ''consistent with or superior to'' the terms of the *pro forma* OATT.

93. In the NOI, the Commission expressed the preliminary view that reforms to the *pro forma* OATT and public utilities' OATTs appear necessary and sought comment on how best to accomplish that. In particular, the Commission sought comment on whether reforms to Order No. 888 should be applied to all public utility transmission providers, including those that are approved ISOs, RTOs, or independent transmission coordinators.

Comments

94. Independent system operators such as MISO, CAISO, and ISO New England submit that many of the concerns raised by the Commission in the NOI already have successfully been addressed by the operation of ISOs and RTOs. Similarly, EEI argues that many of the issues addressed in the NOI are not applicable to RTOs and ISOs because RTOs and ISOs are independent of all market participants and therefore are presumed to not engage in undue discrimination or preferential treatment. PJM argues that, because of its independence, the transparency of its procedures, and the progress achieved in developing effective financial and non-financial congestion management tools, PJM structurally addresses the continuing concerns of the Commission regarding persistent undue discrimination and preference in the industry.

95. EPSA states that it may not be necessary to apply all aspects of the new OATT to ISOs or RTOs. However, rather than delineating either each term that would not apply to an RTO or how such terms might be modified in an RTO tariff, EPSA recommends that the Commission require RTOs, ISOs, and independent transmission coordinators to submit compliance filings upon issuance of the new *pro forma* OATT but allow them to propose waivers of the new requirements based upon appropriate justification.

96. EEI argues that, to the extent that the Commission requires RTOs and ISOs to amend their open access transmission tariffs, the Commission should establish flexible procedures that provide the RTOs and ISOs the right to customize their OATTs consistent with their independent status.

97. Other commenters argue that reforms to existing OATTs should be applied to all market entities, including ISOs, RTOs and independent transmission coordinators.[99] LPPC states that there is little reason for the Commission to be more deferential in considering deviations from the *pro forma* OATT proposed by RTOs or ISOs than it is with respect to investor-owned utilities.

Discussion

98. The Commission proposes to apply the final rule to all public utility transmission providers. The Commission proposes to require all such transmission providers to submit FPA section 206 compliance filings, within 60 days following publication of the final rule in the **Federal Register**, that contain the non-rate terms and conditions set forth in the final rule. We note that certain non-rate terms and conditions, such as Attachment C relating to the transmission provider's ATC calculation methodology and Attachment K relating to the transmission provider's transmission planning process, may require more than 60 days to prepare. We seek comment on an appropriate time period in which to require the submission of these attachments.

99. As we did in Order No. 888, after making their FPA section 206 compliance filings, we propose to allow transmission providers to submit filings under FPA section 205 proposing rates for the services provided for in the tariff as well as non-rate terms and conditions that differ from those set forth in the final rule if those provisions are ''consistent with or superior to'' the *pro forma* OATT.

100. With respect to an RTO or ISO, we recognize that such an entity may already have tariff terms and conditions that are superior to the *pro forma* OATT. Thus, we propose to require RTO and ISO transmission providers to submit FPA section 206 compliance filings, within 90 days following publication of the final rule in the

[96] *See Duke Power,* 113 FERC ¶ 61,288 (2005); *MidAmerican Energy Co.,* 113 FERC ¶ 61,274 (2005); *see also Entergy Services, Inc.,* 110 FERC ¶ 61,295 (2005), *order clarificaiton*, 111 FERC ¶ 61,222 (2005), *order conditionally approving filing,* 115 FERC ¶ 61,095 (2006).

[97] Order No. 888 at 31,770.

[98] *Id.*

[99] *E.g.,* Calpine, LPPC, NRECA, and Santa Clara.

Federal Register, that contain the non-rate terms and conditions set forth in the final rule or that demonstrate that their existing tariff provisions are consistent with or superior to the revised provisions to the *pro forma* OATT. Similarly, after making their FPA section 206 compliance filings, we propose to allow RTOs and ISOs to submit filings under FPA section 205 proposing rates for the services provided for in their tariffs as well as non-rate terms and conditions that differ from their existing tariffs and those set forth in the final rule if those provisions are ''consistent with or superior to'' the *pro forma* OATT.

101. We generally note that the purpose of this NOPR is not to redesign approved, fully-functional RTO or ISO markets. We do not expect that substantial changes to those markets would be required as a result of this NOPR. For example, some RTOs or ISOs have eliminated point-to-point service for internal transactions in favor of a form of more flexible network service. Thus, we would not expect our reforms to ATC to require changes to the way in which such RTOs or ISOs assess whether capacity for traditional network or point-to-point service is available within their footprints. However, there may be elements of the proposed reforms that are superior to what currently exists in some RTOs or ISOs, *e.g.*, transparency, data exchange or planning, which would require the RTO or ISO to conform to the *pro forma* OATT.

2. Non-Public Utility Transmission Providers/Reciprocity

102. In Order No. 888, the Commission conditioned non-public utilities' use of public utility open access services on an agreement to offer comparable transmission services in return.[100] The Commission found that while it did not have the authority to require non-public utilities to make their systems generally available, it did have the ability and the obligation to ensure that open access transmission is as widely available as possible and that Order No. 888 did not result in a competitive disadvantage to public utilities.

103. Under the reciprocity provision in section 6 of the *pro forma* OATT, if a public utility seeks transmission service from a non-public utility to which it provides open access transmission service, the non-public utility that owns, controls, or operates transmission facilities must provide comparable transmission service that it is capable of providing on its own system. Under the OATT, a public utility may refuse to provide open access transmission service to a non-public utility if the non-public utility refuses to reciprocate. A non-public utility may satisfy the reciprocity condition in one of three ways: first, it may provide service under a tariff that has been approved by the Commission under the voluntary ''safe harbor'' provision. A non-public utility using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the *pro forma* OATT. The non-public utility then must offer service under its reciprocity tariff to any public utility whose transmission service the non-public utility seeks to use. Second, the non-public utility may provide service to a public utility under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility may seek a waiver of the reciprocity condition from the public utility.[101]

104. In EPAct 2005, Congress authorized, but did not require, the Commission to order non-public utilities (or ''unregulated transmitting utilities'') to provide transmission services. Section 1231 of EPAct 2005 establishes a new section 211A in Part II of the FPA, which states in part that the Commission ''may, by rule or order, require an unregulated transmitting utility to provide transmission services'' at rates that are comparable to those it charges itself and under terms and conditions (unrelated to rates) that are comparable to those it applies to itself and that are not unduly discriminatory or preferential. The language does not limit the Commission to ordering transmission services only to the public utility from whom the non-public utility takes transmission services, but rather it can reasonably be read to permit the Commission to order the non-public utility to provide ''open access'' transmission service, *i.e.*, service to all eligible customers.

105. In the NOI, we sought comment on whether the Commission should exercise the authority granted to it by Congress in FPA section 211A. If so, we asked whether the Commission should impose this requirement on all unregulated transmitting utilities through a rulemaking proceeding, or whether the Commission should instead apply this new law on a case-by-case basis, through complaints, motions seeking enforcement, or sua sponte action by the Commission.

Comments

106. Several non-public utility commenters suggest that the Commission should not use the authority granted by FPA section 211A in a generic fashion.[102] They argue that there is no need to require unregulated transmitting utilities either to file open access tariffs with the Commission or to require that they adhere to a *pro forma* OATT. APPA asserts that while the Commission may act under FPA section 211A to remedy particular issues that are brought to its attention with respect to lack of access, there is simply no basis for concluding that there currently exists a general problem regarding the provision of transmission service by non-public utility transmission providers which calls for a generic solution. LPPC proposes a regime of voluntary compliance with a set of proposed comparability guidelines.

107. Many commenters argue that the Commission should exercise its authority granted by FPA section 211A by establishing a rule to require unregulated transmitting utilities to provide service under the *pro forma* OATT.[103] EEI believes a rulemaking is essential to ensure that all utilities required to provide open access under FPA section 211A do so and that the Commission should, at a minimum, require unregulated transmitting utilities to file and provide service under the *pro forma* OATT. EPSA and Sempra Global suggest an approach that would not require an unregulated transmitting utility to file an OATT with the Commission until it receives a request for service.

108. EEI argues that the Commission should use FPA section 211A to require unregulated transmitting utilities to provide all services they are capable of providing, not just those that they provide to themselves. In contrast, APPA states that FPA section 211A establishes a ''comparability'' standard applicable to non-public utility transmission owner rates, and a ''comparable and not unduly discriminatory or preferential'' standard for terms and conditions. APPA further states that FPA section 211A requires that unregulated transmitting utilities provide transmission service to others at

[100] These entities are not FPA public utilities and therefore are not subject to the Commission's jurisdiction under sections 205 and 206 of the FPA.

[101] *See* Order No. 888–A at 30,285–86.

[102] *E.g.,* Chelan, Douglas, LDWP, LPPC, Northwest Unregulated TUs, Public Power Council, Rural Utilities Service, Sacramento, Santee Cooper, Snohomish, Tacoma, TAPS, and TVA.

[103] *E.g.,* Ameren, California Commission, Calpine, Cinergy, EEI, First Energy, Memphis Light, Nevada Companies, Northwest IPPs, PNM–TNMP, PPL, Progress Energy, and Suez Energy NA.

rates, terms and conditions ''comparable to those under which the unregulated transmitting utility provides transmission services to itself,'' rather than transmission services that they are ''reasonably capable of providing.''

109. The Canadian Electricity Association believes that the adoption of FPA section 211A requires the Commission to revisit the reciprocity requirement of Order No. 888. According to the Canadian Electricity Association, EPAct 2005 lowered the bar for domestic unregulated transmitting utilities, requiring them only to provide service under terms and conditions that are comparable to those they apply to themselves, rather than terms and conditions that substantially conform or are superior to those in the *pro forma* OATT. If the Commission does not make corresponding changes to the manner in which the reciprocity requirement currently applies to Canadian entities, it argues, the result will be domestic unregulated transmitting utilities being treated better than Canadian entities, which would violate the national treatment obligations under the North American Free Trade Agreement. The Canadian Electricity Association argues that the reciprocity requirement under Order No. 888 must be modified to require that a Canadian entity that seeks open access in the U.S. must provide access to its own transmission system under terms and conditions that are comparable to those the Canadian entity is subject to itself.

Discussion

110. The Commission proposes to retain the current reciprocity language in the *pro forma* OATT, as well as Order No. 888's three alternative provisions for satisfying the reciprocity condition, which are described above: a non-public utility that owns, controls, or operates transmission and seeks transmission service from a public utility must either satisfy its reciprocity obligation under a bilateral agreement, seek a waiver of the OATT reciprocity condition from the public utility, or file a safe harbor tariff with the Commission.[104]

111. We do not propose a generic rule to implement the new FPA section 211A.[105] Rather, we will apply its provisions on a case-by-case basis, such as when a public utility seeks service from an unregulated transmitting utility that has not requested service under the public utility's OATT and the reciprocity obligation therefore does not apply.[106] A customer may file an application with the Commission seeking an order compelling the unregulated transmitting utility to provide transmission service that meets the standards of FPA section 211A. Further, as we indicate below, we expect unregulated transmission providers to participate in the open and transparent regional planning processes that we propose to order and note that, if there are complaints about such participation, we will address them on a case-by-case basis.

112. We disagree with the position of the Canadian Electricity Association. EPAct 2005 did not repeal the reciprocity obligation in Order No. 888. Rather, it granted a new avenue of authority to the Commission to order comparable transmission service from non-public utilities. We are proposing not to exercise this new authority at this time. Rather, we are proposing to retain our reciprocity policy, which was adopted pursuant to sections 205 and 206 of the FPA. By maintaining the same reciprocity requirement for domestic, non-public utilities as for foreign utilities doing business in the United States, the Commission will ensure that foreign entities will continue to be treated no less favorably than domestic, non-public utilities.

V. Proposed Modifications of the OATT

A. Consistency and Transparency of ATC Calculations

113. In Order Nos. 888 and 889, the Commission directed transmission providers to offer their unused transfer capability to the market and to post the amount of ATC[107] on OASIS. At the time those orders were issued, the Commission noted that formal methods did not exist for calculating ATC, but recognized that there were industry efforts underway to develop a consistent, industry-wide method for calculating it.[108] Instead of prescribing a specific methodology for calculating ATC in Order Nos. 888 and 889, the Commission encouraged the industry efforts and required that transmission providers base their ATC calculation methodologies on current industry practices, standards and criteria.[109] In addition, the Commission directed transmission providers to include a description of their ATC calculation methodologies in Attachment C of their tariffs.

114. Ten years later, however, although some progress has been made, the industry still has not developed a consistent, industry-wide methodology for evaluating ATC. In the intervening years, the industry, working through the North American Electric Reliability Council (NERC), has adopted a general definition of ATC, which establishes a basic methodology for evaluating ATC. NERC also has developed a set of guiding principles for calculating ATC and has encouraged further consistency of ATC calculation methodologies on a regional level. NERC defines ATC as the transfer capability remaining on the system for further commercial activity over and above already committed uses. This value is determined by deducting existing transmission commitments (ETC)[110] (including transmission reservations, network and retail customer service), capacity benefit margin (CBM),[111] and transmission reliability margin (TRM)[112] from total

[104] For non-public utilities that choose to use the safe harbor tariff, we note that its provisions must be substantially conforming or superior to the new *pro forma* OATT. A non-public utility that already has a safe harbor tariff may amend its tariff so that its provisions substantially conform or are superior to the new *pro forma* OATT if it wishes to continue to qualify for safe harbor treatment. As the Commission stated in Order No. 888–A, a non-public utility may limit the use of its voluntarily offered safe harbor reciprocity tariff only to those transmission providers from whom the non-public utility obtains open access service, as long as the tariff otherwise substantially conforms to the *pro forma* OATT. *See* Order No. 888–A at 30,289.

[105] We note that LPPC has committed to voluntary compliance with a set of guidelines for the provision of comparable service under FPA section 211A.

[106] We do, however, propose to amend our regulations to make clear that an applicant in a FPA section 211A proceeding against a non-public utility that has submitted an acceptable safe harbor tariff shall have the burden of proof to show why service under the safe harbor tariff is not sufficient and why a FPA section 211A order should be granted. *See* revised 18 CFR 35.28(e)(1)(ii).

[107] *See supra* note 7.

[108] Order No. 889 at 31,607.

[109] *Id.*

[110] NERC does not have a formal definition or standard methodology for ETC.

[111] NERC defines CBM as the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities, whose loads are located on that transmission service provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a load-serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the load-serving entities only in times of emergency generation deficiencies. *See* North American Electric Reliability Council, *Glossary of Terms Used in Reliability Standards,* (Effective April 1, 2005), (NERC Glossary) available at *ftp://www.nerc.com/pub/sys/all_updl/standards/sar/Glossary_07Feb06.pdf.*

[112] NERC defines TRM as the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. *See* NERC Glossary.

transfer capability (TTC).[113] However, NERC's calculation methodology is not prescriptive; it establishes a framework for evaluating ATC, which leaves open to each transmission provider's interpretation and discretion the specific algorithm, data inputs and assumptions needed to assess ATC.[114] Consequently, transmission providers have developed numerous ways to evaluate ATC using their own algorithms, data and modeling assumptions.[115]

115. Although transmission providers across the Nation have developed various methodologies, in general, there are two main approaches to calculating ATC used in the industry. The first is the contract path approach, which is more commonly used by transmission providers in the Western Electricity Coordinating Council (WECC) region.[116] The contract path methodology derives ATC directly from predetermined TTC, ETC, CBM, and TRM values derived consistent with contract path transmission rights. The second method is the flowgate [117] approach, which is used more widely in the Eastern Interconnection.[118] The flowgate methodology is based on physical power flow models. The flowgate calculation first determines AFC and then converts AFC into ATC and derives TTC for the OASIS posting. The differences between the two approaches may not result in significantly different ATC values if consistent data inputs and industry acceptable modeling assumptions are used. Without a consistent and transparent approach to evaluating ATC, transmission customers will remain wary when service is denied and transmission providers will be the subject of suspicion and heightened scrutiny, especially given the increasingly congested state of the Nation's electric grid.

Consistency

116. Generally, transmission providers calculate ATC by creating a base model of their system using a set of data inputs and assumptions, which are determined by the transmission provider. The transmission provider uses the model to perform various computer simulations of the operations of its system to determine the levels of transfer capability available on the system. The types of data and assumptions used in the models include, for example, facility ratings, the operating status of facilities, and generation dispatch, which might be supported by history, transmission plans, or the judgment of the transmission provider. For example, a transmission provider could use its judgment to reduce a facility rating or model certain facilities as out of service, which would have the effect of calculating a lower TTC value. A transmission provider also may use generation dispatch assumptions to limit transfer capability that otherwise would have been available to independent generators, thereby favoring the transmission provider's own generation. A transmission provider usually assumes that designated network resources are dispatched in economic merit order. However, a transmission provider has the discretion to decide which of the generators that are not designated network resources will be modeled in-service. Assumptions like these influence the loading on transmission lines in the model and heavily influence the resulting ATC. Having standards in place that address the calculation of ATC components, data inputs, and modeling assumptions would help ensure non-discriminatory treatment by limiting a transmission provider's ability to use discretion to the disadvantage of competitors and the market.

117. As noted above, NERC does not have a formal definition of ETC. Without clear criteria for what should be included in a transmission provider's ETC, a transmission customer might not know whether ETC is being over- or underestimated. For example, a transmission provider could set aside more capacity for native load than is realistically expected to occur. This could happen if a transmission provider includes in ETC excess capacity for a load-serving entity (such as capacity to meet generation reserve requirements) but then also has a CBM component in its calculation of ATC that includes the same capacity. A transmission provider also could overestimate its ETC by double-counting the same transmission reservations in its ATC calculation. For example, this could happen if a transmission provider fails to replace a transmission reservation with the associated real-time schedule, and as a result does not release non-firm ATC. A consistent process for calculating ETC will limit the subjectivity of the transmission provider's decisions and provide a more uniform method for estimating ETC.

118. With respect to the modeling of a particular transaction, when information concerning the source is unknown, a transmission provider has the discretion to select which generator(s) will be used as a source.[119] There are no standards for how that modeling should be done and, consequently, a transmission provider could model a source using single or multiple generators by increasing (scaling up) their output. In general, modeling a transaction using multiple generators as a source is less conservative for the transmission system than modeling a transaction using a single generator as a source. Modeling a transaction using multiple generators as a source typically results in a higher ATC value. Conversely, when a transmission provider models a transaction using a single generator as a source, this can result in a lower ATC value depending on the location of the generator. Modeling of contingency outages used for calculating ATC is another area within the discretion of the transmission provider. Although the type of contingency, such as single contingency (n–1), is determined by governing reliability criteria,[120] the transmission provider determines which specific contingencies will be used for the ATC calculation. The common industry practice is to consider the loss

[113] NERC defines TTC as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. *See* NERC Glossary.

[114] *See* NERC, *Available Transfer Capability Definitions and Determination: A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market* (1996) available at *ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/atcfinal.pdf.*

[115] *See supra* note 59.

[116] *See, e.g.*, Determination of Available Transfer Capability within the Western Interconnection (June 2001), available at *http://www.wecc.biz/documents/library/procedures/ATC-apprdec01.pdf.*

[117] A flowgate is a designated point on the transmission system used in the modeling of power flows. While NERC currently does not have a formal definition for AFC, the power industry commonly defines AFC as a measure of the capability remaining on a flowgate for future uses, after considering the effect of prior sales. Mathematically, the industry measures AFC as AFC = Flowgate rating—[(base case flow)—(impacts of existing reservations)]—$\text{Flowgate}_{\text{CBM}}$—$\text{Flowgate}_{\text{TRM}}$.

[118] *See, e.g.*, PJM Manual 2: Transmission Service Request (April 14, 2005), available at: *http://www.pjm.com/contributions/pjm-manuals/pdf/m02v08.pdf*

[119] Transmission providers do not always know the generator used as a source of energy provided under contracts that qualify as designated resources; the only requirement is that the network customer have an executed contract that commits it to purchase noninterruptible power. *See Wisconsin Public Power Inc.* v. *Wisconsin Public Service Corp.,* 84 FERC ¶ 61,120 at 61,650–51 (1998).

[120] Standard TPL–001–0, Table I. Transmission System Standards—Normal and Emergency Conditions, NERC Reliability Standards for the Bulk Electric Systems of North America (effective April 1, 2005).

of each transmission facility at voltage 100 kV and above. However, the lack of standards governing transfer analysis allows the transmission provider to use its discretion to monitor outages only of facilities at 230 kV and above, ignoring the limitations that may exist for the loss of the facilities at lower voltages, such as 115 kV or 138 kV. Consequently, ATC values may vary substantially, with ATC being much higher when monitoring contingencies of facilities at 230 kV and above, and much lower while monitoring the loss of all facilities (voltage 100 kV and above).

119. Furthermore, in calculating ATC, transmission providers set aside a portion of transfer capability in the form of CBM and/or TRM to provide for adequate generation reserves and account for uncertainties or contingencies, respectively. Generally, CBM is the amount of firm transmission transfer capability held back by the transmission provider so that load-serving entities, whose loads are located on the transmission provider's system, can access remote generation reserve from interconnected systems in times of emergency generation deficiencies. Some believe it is necessary for transmission providers to set aside a portion of their TTC to ensure that their ties with other systems remain available for this purpose. There are no consistent industry-wide standards, however, for determining how much transfer capability should be set aside as CBM. There is also no common approach to whether the capacity is set aside for Native Load Customers, as defined in section 1.19 of the *pro forma* OATT, for retail load, or for all load-serving entities. The lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside has the potential to result in the transmission provider setting aside capacity that it might not otherwise need to, thus increasing costs for native load customers and blocking other firm uses of the transmission system.[121]

120. Similarly, TRM is the amount of transmission transfer capability reserved by the transmission provider to ensure that the transmission network will be secure under a reasonable range of uncertainties in system conditions. Because TRM and CBM are both maintained in part for the loss of generators, there exists the possibility of double-counting reliability margins for the loss of the same generation.

121. Moreover, a transmission provider also can use more conservative inputs and assumptions for calculating ATC and performing system impact studies (that tend to minimize ATC) when it is assessing a long-term transmission service request, but use less conservative inputs and assumptions (that tend to maximize ATC) when it is performing system planning for retail native load. This creates the potential for undue discrimination where a transmission provider uses one set of data and assumptions to evaluate third party requests and another set of data and assumptions to plan its system to serve its own load.

Data Exchange Among Transmission Providers

122. The lack of a consistent ATC calculation methodology combined with limited coordination between transmission providers can result not only in inefficiencies but unjust and unreasonable terms and conditions of service, especially for a customer seeking contiguous transmission service from multiple transmission providers. The ATC values posted by a transmission provider are often inaccurate for reasons beyond the control of the transmission provider. A transmission provider may post ATC values in good faith and attempt to provide transmission service based on these values only to discover later that the transfer capability that it thought was available no longer exists due to decisions made by other transmission providers that it did not know about at the time it made its calculations. Accurate ATC calculation requires reliable and timely information about such things as load, generation dispatch, facility outages, and transactions on neighboring systems. Transmission providers also may apply differing assumptions and criteria to ATC calculations, which may produce wide variations in posted ATC values for the same transmission paths. All of these considerations make it difficult for an individual transmission provider that operates one part of an interconnected grid to calculate ATC accurately.

123. This lack of communication and coordination between transmission providers of ATC data can also affect reliability. As discussed above, a transmission provider could grant transmission service without being aware of the real impact that service may have on an adjacent transmission provider's system, thus degrading the reliability of the interconnected system. Inaccurate ATC values can cause overselling of transfer capability, which can lead to curtailments or transmission loading relief (TLR) actions to avoid exceeding thermal, voltage, and/or stability limits.

Transparency

124. As discussed, the lack of a consistent, industry-wide methodology for assessing ATC makes undue discrimination difficult to detect. This problem is further exacerbated by a lack of transparency surrounding the calculation methodology used by transmission providers. Although the Commission requires transmission providers to file their methodologies for calculating ATC in their tariffs, transmission providers often have responded by filing very general narrative descriptions of their calculation methodologies (often simply referring to the general NERC definition)[122] without further specification of the mathematical algorithm, data inputs, and modeling assumptions used to perform the calculation.

125. Other than the description of the ATC methodology provided in transmission providers' tariffs, third parties often have limited access to information concerning the specific algorithms, data and assumptions used by transmission providers to evaluate their ATC, which makes it difficult to verify or challenge a transmission provider's ATC calculations. The Commission requires each transmission provider to calculate and post ATC and TTC values for each posted path.[123] Transmission providers also are required to make publicly available, on request, all data used to calculate ATC and TTC for any constrained path.[124] Additionally, transmission providers are required to make publicly available, on request, system planning studies or

[121] The Commission has explained that the *pro forma* OATT requires both transmission customers and transmission providers using the transmission system to serve network load (including bundled retail native load) to designate their resources and loads so that the transmission customers and transmission providers would have no incentive to designate network resources above their needs and, in so doing, tie up valuable transmission capacity. *Aquila Power Corp.* v. *Entergy Services, Inc.*, 90 FERC ¶ 61,260, *reh'g denied*, 92 FERC ¶ 61,064 (2000), *reh'g denied*, 101 FERC ¶ 61,328 (2002), *aff'd sub nom. Entergy Services, Inc.* v. *FERC*, 375 F.3d 1204 (D.C. Cir. 2004) (*Aquila*).

[122] *See, e.g.*, the OATTs of Aquila, Inc., Southern, and Tucson Electric Power Company.

[123] *See* 18 CFR 37.6 (b) (2005). A posted path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. *Id.* 37.6 (b)(1)(i).

[124] *Id.* 37.6 (b)(2)(ii). A constrained posted path is defined as any posted path having an ATC value less than or equal to 25 percent of TTC at any time during the preceding 168 hours or for which ATC has been calculated to be less than or equal to 25 percent of TTC for any period during the current hour or the next 168 hours. *Id.* 37.6 (b)(1)(ii).

network impact studies performed for customers to determine network impacts. Furthermore, subsequent to Order Nos. 888 and 889, the Commission required each transmission provider to post (and update) the CBM value for each path for which it already posts ATC and TTC, as well as a narrative explanation of its CBM practices.[125]

126. Yet, despite these requirements, third parties often are unable to gain access to sufficient information surrounding a transmission provider's ATC calculation methodology. As a preliminary matter, we note that while the OASIS requirements regarding the availability of information related to ATC and TTC calculations are still in effect, they have been affected by restrictions that have been placed upon the availability of critical energy infrastructure information (CEII) in the interest of national security.[126] Therefore, system planning and network impact studies and models typically are no longer available on a transmission provider's OASIS. Furthermore, transmission customers are often unable to access other information such as load flow base cases and associated files. In sum, although existing Commission regulations are intended to provide a certain level of transparency, this transparency is undermined by a number of factors, including the absence of detailed descriptions of the data inputs, assumptions, and criteria used to determine the data included in ATC calculations, as well as the inability of customers to access certain of this data because of, among other reasons, security concerns.

Recent Industry Efforts To Improve the Consistency and Transparency of ATC Calculations

127. The industry recently has taken some steps to address the lack of consistency and transparency in the way ATC is calculated. NERC formed a Long-Term AFC/ATC Task Force to review NERC's standards on ATC, which issued a final report in 2005 (NERC Report)[127] that made recommendations for greater consistency and greater clarity in the calculation of ATC. The task force also recommended greater communication and coordination of ATC information to ensure that neighboring entities exchange relevant information. Based on the recommendations in the NERC Report, NERC has two Standards Authorization Request (SAR) proceedings underway to revise the standards on ATC. The first SAR proceeding proposes changes to the existing standards on ATC to, among other things, further establish consistency (on a regional basis) in the calculation of ATC and to increase the clarity of each transmission provider's ATC calculation methodology. The second SAR proceeding proposes certain changes to NERC's existing standards on the ATC components of CBM and TRM. This proceeding also calls for greater regional consistency and transparency in how CBM and TRM are treated in transmission providers' ATC calculations. Also, based on the recommendations in the NERC Report, the North American Energy Standards Board (NAESB) has a proceeding underway to develop business practice standards to enhance the processing of transmission service requests, which use TTC, ATC and/or AFC.

128. Following the release of the NERC Report, the Commission issued the ATC NOI[128] seeking comments on the contents of the NERC Report. More specifically, the Commission sought comments on the NERC Report's recommendations on areas in which CBM and TRM could be more specific and whether these recommendations go far enough in promoting a common CBM and TRM methodology within each region. The Commission also sought comments on the definitions of ATC, AFC, CBM and TRM. The Commission also solicited comments on the advisability of revising and standardizing ATC, AFC, TRM and CBM values. In addition, the Commission sought comments on the advisability of developing interconnection-wide standards for the Eastern Interconnection and WECC. Finally, the Commission asked for comments on the most expeditious way to obtain industry-wide standards for ATC calculations.

129. Furthermore, in the NOI, the Commission sought comments on whether undue discrimination is most likely to occur in areas such as ATC calculation where the transmission provider retains discretion as to how to implement a particular tariff provision.

Comments

Comments on Consistency

130. Many commenters express general support for some level of increased consistency in ATC calculations.[129] Some commenters urge the Commission to develop a consistent, industry-wide methodology for calculating ATC.[130] Constellation asserts that although transmission providers need to be innovative and flexible in many respects, a requirement that all transmission providers use the same methodology to determine ATC would not only remedy the lack of clarity that surrounds these calculations and reservations, but would provide regulatory certainty and assist transmission customers in predicting the outcome of transmission service requests. This, in turn, Constellation suggests, would expand the commercial opportunities for transmission customers. According to Alcoa, AWEA and Renewable Energy, the industry-wide methodology should be a flow-based methodology, rather than a contract path methodology because they believe that a flow-based analysis provides a more realistic view of actual system usage and results in a more accurate assessment of ATC. Exelon further suggests that this uniform methodology should also apply to all transmission providers, including RTOs.

131. Other commenters argue against a one-size-fits-all approach, but rather express a preference for greater uniformity at a regional level to recognize regional differences.[131] These commenters suggest that due to differences in transmission systems or regions, it may not be practical or possible to standardize the ATC calculation methodology on an industry-wide basis. For example, Powerex cautions that nationwide standardization may not take into account the unique characteristics of particular systems or regions, such as the differences attributable to the West's contract-path model and the East's flow-based model, as well as differences attributable to the primarily hydro-

[125] *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 FERC ¶ 61,099 (1999) (CBM Order).

[126] *See Critical Energy Infrastructure Information*, Order No. 630, 68 FR 9857 (Mar. 3, 2003), FERC Stats. & Regs. ¶ 31,140 (2003), *order on reh'g*, Order No. 630–A, 68 FR 46456 (Aug. 6, 2003), FERC Stats. & Regs. ¶ 31,147 (2003), *order on clarification*, Order No. 662, 70 FR 37031 (Jun. 28, 2005), FERC Stats. & Regs. ¶ 31,189 (2005); *see also* 18 CFR 388.113 (2005).

[127] *See supra* note 115.

[128] *Supra* note 9.

[129] *E.g.*, Alcoa, Ameren, AWEA, Calpine, Constellation, Cottonwood ATC NOI Comment, ELCON, Exelon, FTC ATC NOI Comment, Midwest ISO ATC NOI Comment, Midwest SATS, New York Commission ATC NOI Comment, North Carolina Commission, Occidental, South Carolina E&G, TAPS, and TransAlta.

[130] *E.g.*, Alcoa, AWEA, Constellation, Exelon, Occidental, and Renewable Energy.

[131] *E.g.*, Alberta Intervenors, APPA, Bonneville, International Transmission, ISO/RTO Council, LDWP, MidAmerican, Nevada Companies, Powerex, Progress Energy, Public Generating Pool, Public Power Council, Salt River, Santa Clara, Snohomish, Tacoma Power, TANC, and TDU Systems.

based systems in the Pacific Northwest.[132] Similarly, TANC argues that flowgate terminology and application in ATC calculation should not be required in the West because it does not adequately represent the nature of the many transmission constraints in the West. Other commenters caution that too much uniformity of the ATC calculation methodology could have an adverse effect on grid reliability.[133] In addition, some commenters urge the Commission not to adopt an ATC methodology that is so prescriptive that it inhibits new or better practices or imposes a wholesale revision of accepted market designs and processes that are working within established markets.[134]

132. Several commenters argue against any efforts to further standardize ATC calculations.[135] In its comments filed in the ATC NOI proceeding, LDWP asserts that the alleged problems with ATC are overstated. Moreover, it argues, the benefits of squeezing additional ATC from existing systems have not been established given that transmission customers can already request any capacity they need regardless of the posted ATC and transmission providers are required to make a good-faith effort to evaluate each request. Several commenters argue that the circumstances of individual transmission customers vary and often ATC calculations rely on the individual transmission provider's knowledge of its facilities and system conditions.[136] For example, Southern contends that too many factors go into the calculation of ATC to make the adoption of a static set of standards feasible. In fact, Southern and EEI maintain, standardization of ATC calculations is inconsistent with maintaining reliability because the circumstances of transmission providers vary significantly, and they must operate their systems based on their specific circumstances. In addition, LG&E maintains that standardizing ATC will not necessarily eliminate the need for TLR procedures to deal with load forecast errors and unplanned generation and transmission outages. Furthermore, some commenters argue that increased uniformity could impose significant costs upon utilities.[137]

133. Some commenters urge the Commission to increase the consistency of the elements of the ATC calculation, such as the kind of data inputs that transmission providers consider when evaluating ATC—including load levels, generator outage information, transmission outage information and generation dispatch information.[138] Exelon also urges the Commission to establish the assumptions that transmission providers use in their ATC methodologies—such as how transmission reservations are accounted for and which reservations to model. Exelon also cites an example of modeling transaction counterflows, noting that uniform rules for data inputs are needed to ensure that transaction counterflows are modeled identically in both the planning and ATC/AFC calculation processes. In addition, commenters urge the Commission to establish the procedures for determining ATC (and its components) and to require a transmission provider to show that it has properly followed all required procedures.[139] Among other things, commenters suggest that the Commission should establish how frequently ATC is calculated, how frequently inputs are updated, require transmission providers to determine AFC instead of ATC, and require transmission providers to recognize all third-party flowgates that are requested to be monitored. In addition, several commenters state that the Commission should require that the methodology and inputs for ATC calculations be consistent with the transmission provider's planning or operating criteria.[140]

134. Several commenters urge the Commission to allow the industry, working through NERC and NAESB, to complete efforts already underway to further increase consistency of ATC (and its components), as well as certain related business practices.[141] However, many of these commenters urge the Commission to give the industry, working through these organizations, specific guidance on what issues to decide and the parameters for the discussions.[142] Furthermore, commenters state that the Commission should establish a date certain for completion of these industry efforts,[143] and should also take an active role in the process.[144]

135. Other commenters suggest that the Commission should require that an independent entity develop and/or monitor a transmission provider's ATC methodology and its ATC calculations.[145] For example, Constellation states that it does not believe that the solution is to prohibit the transmission provider entirely from exercising its discretion, but instead to require transmission providers to retain an independent entity that can perform certain functions on a consistent, unbiased basis. In addition, the Arkansas Commission asserts that section 1281 of EPAct 2005[146] gives the Commission the authority to require the use of an independent coordinator of transmission to provide independent and verifiable transparency over critical Order No. 888 functions, such as ATC calculations.

136. Several commenters specifically address the lack of consistency in the industry on the definition and use of CBM and TRM. For example, TAPS notes that NERC does not require any transmission provider to reserve CBM. In addition, TAPS states, even in those regions that use CBM, there is often no regional methodology; it is up to the vertically integrated transmission provider to determine whether it wants to reserve CBM at all and at which interfaces, with no effective review of that determination. TAPS also states that TRM should be clearly defined and, if truly required for reliability, then all transmission providers should reserve it. According to TAPS, the Commission should define TRM in a manner that leaves no discretion as to whether, where, and how much capacity to set aside. EPSA also notes that there is a disconnect between the planning and expansion processes and the assumptions transmission providers use to calculate CBM and TRM.

137. TANC states that the Commission should closely examine the necessity of CBM in ATC calculations. Bonneville argues that there should only

[132] Accord LDWP ATC NOI Comment, Public Power Council, Salt River, Snohomish, Tacoma, and TANC.

[133] *E.g.,* NERC ATC NOI Comment, Public Power Council, and TVA.

[134] *E.g.,* ISO/RTO ATC NOI Comment and Powerex.

[135] *E.g.,* Cinergy, EEI, LG&E, LDWP ATC NOI Comment, National Grid, PPL, Public Generating Pool, San Diego G&E, Southern, TVA, and Xcel.

[136] *E.g.,* Southern and TVA.

[137] *E.g.,* International Transmission and LG&E.

[138] *E.g.,* Exelon and TDU Systems.

[139] *E.g.,* Ameren and Exelon.

[140] *E.g.,* Exelon, ISO/RTO ATC NOI Comment, MISO, and NERC.

[141] *E.g.,* Ameren, APPA ATC NOI Comment, Duke, EEI, Exelon, International Transmission Company ATC NOI Comment, ISO/RTO Council ATC NOI Comment, KCP&L, MidAmerican ATC NOI Comment, MISO ATC NOI Comment, Progress Energy, Southern, TAPS, TDU Systems, TransAlta, and WestConnect ATC NOI Comment.

[142] *E.g.,* APPA ATC NOI Comment and International Transmission ATC NOI Comments.

[143] *E.g.,* Duke and Exelon.

[144] *E.g.,* APPA ATC NOI Comment, TAPS, and TransAlta.

[145] *E.g.,* Arkansas Commission, Calpine, Constellation, EPSA, New York Commission, Occidental, and TDU Systems.

[146] EPAct 2005 sec. 1281(to be codified at section 220 of the FPA, 16 U.S.C. 824t), which concerns electricity market transparency rules.

be one commercial margin instead of multiple margins (TRM, CBM, and others).

Comments on Data Exchange Among Transmission Providers

138. Several commenters argue that the Commission should establish standards for resolving seams issues between transmission providers where each transmission provider uses a different methodology for calculating ATC.[147] Constellation and BC Transmission assert that when different transmission providers have different methods for determining ATC, this can lead to inefficiencies, including market confusion, lost sales/purchase opportunities, and unnecessary curtailments.

139. Commenters identify various elements of the ATC calculation methodology that they argue should be more consistent. For example, BC Transmission states that some of the elements that are calculated differently at the seams include the level of TRM, the level of CBM, the approach regarding the sale (or not) of TRM as non-firm capacity, assumptions regarding controlling interchange and assumptions regarding operating conditions. Similarly, MidAmerican in its response to the ATC NOI suggests that greater coordination is needed on partial path review, policies for decrementing AFC and redispatch policies. For example, MidAmerican references problems associated with coordination between transmission providers on partial path treatment. Specifically, when transmission service involves a path across multiple systems, a given flowgate may be evaluated several times by various providers on the transmission path. Because of a lack of coordination between these providers, AFC on the flowgate may be decremented multiple times for the same transmission service request, and service may be denied even when the true available capacity on the flowgate is sufficient to allow the request to be granted. Exelon also states that certain data inputs must be coordinated across all transmission providers in an interconnection including load levels, transmission outages, generation outages and generation dispatch. In addition, Exelon states, the Commission should establish how transmission providers account for transmission reservations in an ATC/AFC calculation.

140. Moreover, NY Commission suggests that this problem goes beyond the non-independent transmission providers. According to NY Commission, in order for RTOs to properly determine tie flow limits, they need access to certain information from the control region on the other side such as load levels and distributions, generator dynamic capability and expected outputs, phase shifter positions and standard contingencies required by that control area. In addition, NY Commission states, these inputs need to be updated daily.

141. Finally, Alcoa states that the potential for underestimating ATC is likely another consequence of the fundamental conflict between the contract path model and the electricity path model of contracting for electric energy. According to Alcoa, outside of ISO/RTO systems, utilities may not have enough data available to compute ATC, since they may not be able to accurately complete all relevant parallel path transactions.

Comments on Transparency

142. Commenters are overwhelmingly in favor of greater transparency in the ATC calculation methodology to provide more assurance that a transmission provider is not performing its ATC calculations in an inconsistent or unduly discriminatory manner.[148] EEI suggests that transmission providers could make their base case load flow studies on which they base their calculation of ATC available to transmission customers, subject to security and confidentiality protections. Other commenters state that greater transparency could be achieved through the imposition of additional posting requirements on OASIS.[149] These commenters argue that the Commission should require transmission providers to post their discrete methodologies and algorithms for evaluating ATC, as well as their transmission modeling information and their various assumptions. Commenters further suggest that transmission providers should be required to provide information regarding planned outages, and to ensure consistent treatment of outage information between control areas.[150]

143. In its reply comments, Southern acknowledges that greater transparency would reduce concerns of undue discrimination, but cautions the Commission against imposing unnecessary and duplicative posting requirements and notes that much of the information that commenters have asked the Commission to make transparent is in fact already publicly available through a variety of sources.

144. In addition, some commenters urge the Commission to impose meaningful reporting requirements.[151] In this regard, Constellation asserts that the Commission should modify the *pro forma* OATT to require that transmission providers post systematic, timely and accurate reporting of certain service metrics such as transaction requests approved, rejected, confirmed, and curtailed. Similarly, Cottonwood states that transmission providers should be required to provide information detailing why a particular transmission request was denied and whether there are other available alternatives. In addition, several commenters argue that transmission providers also should be required to post their relevant business practices, operating standards, protocols and internal guidelines that affect transmission service.[152] TDU Systems also urge the Commission to require transmission providers to explain why transactions are allowed to flow even when the posted ATC value was zero.

145. EPSA argues that capacity is unnecessarily held from the market when transmission providers reserve excessive amounts for their native load and when they fail to make capacity available through redispatch. EPSA states, however, that there is no way of knowing whether there is a hoarding problem because there is no requirement to post the necessary real time information on transmission utilization, and recommends a requirement to post such information. Powerex contends there is an incentive for transmission providers to hoard because grandfathered or other firm rights held by the transmission provider to serve native load are subsequently used for wholesale marketing purposes. It further states, however, that evidence of anticompetitive practices is difficult to obtain because of a lack of transparency. Powerex supports increased requirements for both uniform and transparent ATC calculation.

146. Several commenters urge the Commission to establish compliance review procedures and impose sanctions for violations to ensure that transmission providers are accountable

[147] *E.g.,* BC Transmission, Constellation, Exelon, NY Transmission, Renewable Energy, and TDU Systems.

[148] *E.g.,* Alcoa, Ameren, APPA, Calpine, CEOB, Cinergy, Constellation, Cottonwood, Duke, EEI, ELCON, HQ Energy, LDWP, MidAmerican, Midwest ISO, Midwest SATs, Powerex, PPL, Progress Energy, Public Generating Pool, Public Power Council, Salt River, Southern, TANC, TAPS, TDU Systems, TransAlta, and TVA.

[149] *E.g.,* Calpine and PPL.

[150] *E.g.,* H.Q. Energy and Powerex.

[151] *E.g.,* Constellation, Cottonwood, and TDU Systems.

[152] *E.g.,* Powerex and TransAlta.

for ensuring that their ATC calculations are correct.[153] In its response to the ATC NOI, Cottonwood states that the Commission should develop specific tests (benchmarks) to monitor transmission providers' performance. In addition, HQ Energy states that the Commission should conduct periodic reviews of whether non-independent transmission providers have properly calculated and allocated ATC. ELCON states that the Commission should place the burden of proof to depart from its ATC methodology on the transmission provider and include specific penalties in the tariff for transmission providers that are found to be in violation.

147. HQ Energy and Powerex also state that the Commission should require transmission providers to ensure that staff is available at all times to respond to customer inquiries regarding real-time transactions.

Discussion

148. We propose to address the potential for remaining undue discrimination in the determination of ATC by requiring industry-wide consistency and transparency of certain definitions, data, modeling assumptions and components of ATC. We propose to provide general guidance regarding the aspects of ATC calculation that we believe should be more consistent and direct public utilities, working through NERC and NAESB, to use our guidance to revise the relevant standards and business practices. In addition, we propose to require increased detail in the *pro forma* OATT regarding the method of calculating ATC and to amend our OASIS regulations to require increased transparency.

149. Though NERC and NAESB currently are working on certain proposals to address the problems we have identified,[154] we are concerned that without guidance, direction and a firm deadline, these industry developments may not succeed due to other conflicting priorities. We believe that the existing NERC and NAESB processes are well-suited to achieving greater consistency in ATC calculations. It is our expectation that NERC and NAESB will expand on the work they have already undertaken to achieve the goals we propose to set out for them.

150. We propose to take this action pursuant to our obligation under FPA section 206 to remedy undue discrimination in the provision of transmission service. Transmission providers in general enjoy substantial discretion in establishing and interpreting the specific algorithms, data, and assumptions needed to assess ATC. Though we do not believe it is possible or necessary to entirely eliminate discretion, unchecked discretion affords a transmission provider the ability and opportunity to discriminate in its favor (and its affiliate's favor) against third parties in how it calculates and allocates ATC and, therefore, may be unjust, unreasonable, unduly discriminatory and preferential. Transmission providers have an incentive to understate ATC on transmission paths that would be valuable to power sellers that are competitors to the transmission providers' own (or their affiliates') power sales. Where transmission congestion exists, the methodology for calculating ATC will effectively determine whether competitors have access to the transmission grid, and the lack of any consistent methodology for calculating ATC gives transmission providers excessive discretion in making this determination.

151. The lack of consistency and detail in the determination of ATC can facilitate undue discrimination in a variety of ways. Transmission providers may use generation dispatch assumptions that result in limited capacity being available to merchant generators. They also may use different inputs and assumptions for purposes of calculating ATC for third parties than they do for system planning for retail native load. As noted above, a transmission provider could reduce a facility rating or model certain facilities as out of service, which would have the effect of underestimating TTC. In determining ETC, transmission providers have discretion to determine the capacity needed and set aside for native load usage. Each of these exercises of discretion has a significant effect on ATC.

152. The lack of transparency into how a transmission provider calculates and allocates its ATC (including all assumptions and data inputs) makes it difficult to detect discriminatory behavior. This lack of transparency frustrates and increases the costs of compliance and enforcement efforts. Many transmission providers have urged the Commission to provide greater clarity in the rules for OATT service,[155] particularly given the threat of the Commission's new civil penalty authority.

153. In addition to our preliminary finding that the lack of consistent, industry-wide ATC calculation standards is unjust and unreasonable under FPA section 206, we believe that it poses a threat to the reliable operation of the bulk-power system. A transmission provider needs to know how much electricity its system can carry. The lack of a consistent, industry-wide methodology for evaluating ATC and the lack of data sharing among transmission providers often leads to problems in determining the appropriate ATC value. Despite a transmission provider's good faith attempt to calculate and post accurate ATC levels, it can find that transmission that it thought was available on its system no longer exists because it was unaware of decisions by other transmission providers. This, in turn, can threaten the reliable operation of the interconnected transmission system.[156]

154. As a result of reliability effects of inconsistent ATC calculations, our proposal for greater consistency and transparency also is supported by our new authority under section 215 of the FPA, which gives the Commission jurisdiction to certify an Electric Reliability Organization (ERO) and to approve reliability standards that are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission also has authority to order the ERO to submit a reliability standard that the Commission considers appropriate to implement FPA section 215.[157] On April 4, 2006, NERC submitted an application to be certified as the ERO, as well as proposed reliability standards.[158] In this NOPR, we direct our guidance to public utilities and recommend that they implement our direction by working with NERC. However, this is not intended to prejudge the outcome of the ERO proceeding. Though the Commission

[153] *E.g.,* Cottonwood ATC NOI Comment, ELCON, HQ Energy, NRECA, Occidental, and Powerex.

[154] We understand that two NERC standard authorization requests related to ATC/ TTC/AFC and CBM/TRM were approved earlier this year, and that drafting of the standards' revision is underway. We further understand that NAESB has a concurrent drafting effort underway for associated business practices that will follow a coordinated path with the NERC process. See *http://www.nerc.com/filez/standards/MOD-V0-Revision.html.*

[155] *E.g.*, Ameren, APPA ATC NOI Comments, Duke, EEI, Exelon, International Transmission Company ATC NOI Comments, ISO/RTO Council ATC NOI Comments, KCP&L, MidAmerican ATC NOI Comments, MISO ATC NOI Comments, Progress Energy, Southern, TAPS, TDU Systems, TransAlta, and WestConnect ATC NOI Comments.

[156] According to NERC, ''the lack of standardization and more ignificantly, limited coordination can negatively impact both the market, through the need for a large number of [TLR] actions (or curtailments in WECC) and, on occasion, reliability when even the use of TLRs provides insufficient relief on some critical interfaces.'' See NERC Report at 1.

[157] Section 215(d)(5).

[158] *See* Docket Nos. RR06–1–000 and RM06–16–000.

will act independently on the reliability standards proposed by NERC in Docket No. RM06–16–000, we believe it is prudent to provide our guidance now on NERC's reliability standards related to ATC by providing specific direction on what should be more consistent and a timeframe for completion of NERC's efforts.[159] As we indicated above, the lack of consistency, data exchange and transparency in ATC calculations not only can increase the opportunities for undue discrimination but also can threaten reliability. We therefore believe that Commission action pursuant to FPA section 215 may be appropriate on reliability standards related to ATC calculation. Any action on these reliability standards that is taken in Docket No. RM06–16–000 (the ERO standards rulemaking) will be coordinated and consistent with our determinations regarding ATC calculation in this proceeding.[160]

Consistency

155. The Commission proposes to require public utilities, working through NERC, to develop the standards we set forth below within 6 months of the final rule in this proceeding. Consistent with NERC's existing efforts, we propose to require the development of standards for: (1) ATC/AFC, TTC/Total Flowgate Capacity (TFC), ETC, CBM, and TRM calculation methodologies, (2) data inputs, (3) modeling assumptions, (4) ATC calculation frequency, and (5) data exchange and coordination processes. We further propose to require public utilities, working through NAESB, to work with NERC to identify the appropriate business practices to complement the standards developed by NERC. We discuss below each of the elements for which we propose to require more consistency. We seek comment on these elements of the ATC calculation and, in particular, whether certain elements are more susceptible to further consistency than others and whether certain elements should be prioritized over others because they represent the source of most disputes between transmission providers and customers. We recognize the need to focus on those elements of the ATC calculation that are most susceptible to further consistency and most important in terms of eliminating opportunities for undue discrimination.

156. The Commission recognizes that transmission providers use several basic types of ATC calculation methodologies (with various permutations), and does not believe that a single ATC calculation methodology must be applied by all transmission providers.[161] However, we agree with commenters who argue that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. Accordingly, we propose to achieve greater consistency in ATC calculations by directing the development of consistent definitions of the components of ATC, as well as consistent data inputs, data exchange and coordination protocols, and modeling assumptions, as discussed further below. We believe that this level of consistency will go a long way toward producing more coherent and uniform determinations of ATC across a region, thereby helping to eliminate the potential for undue discrimination.[162]

157. We propose to direct public utilities, working through NERC, to develop consistent practices for TTC/TFC calculation methodologies. We recognize that the NERC reliability regions have historically calculated transfer capability using different approaches.[163] However, we expect that guidelines can be developed for the calculation of transfer capability that use a common approach to model power transfers. In addition, we believe that the criteria used for identifying flowgates and determining TTC/TFC can be more consistent.

158. The Commission believes that the lack of consistency of ETC permits too much discretion in determining how much capacity a transmission provider sets aside for native load, including its network customers. We believe that the development of an industry-wide methodology can limit this discretion. Therefore, we propose to require the development of a consistent methodology for determining the capacity needed and set aside for native load usage. In addition, we propose that accounting for transmission reservations in an ATC/AFC calculation also should be more consistent. Presently, there are two main methods in use. One method models all ''appropriate reservations'' [164] in the power flow base case model. The other method models only those reservations that are expected to be actually scheduled and accounts for others by decrementing flowgate AFC. It is important for consistency to use the same calculation technique when modeling these types of reservations. Therefore, we propose that public utilities, working through NERC, establish and specifically identify which reservations they use in determining ETC.

159. The Commission has previously addressed the lack of a consistent industry-wide methodology for determining CBM. Following a two-day technical conference, the Commission held in the CBM Order [165] that transmission providers continue to wield significant latitude in interpreting how CBM is determined. The Commission directed that the CBM set-aside be more transparent, more accurate, and more widely available.[166] We remain concerned, however, that transmission providers have preferential access to the interface capacity that is set aside. This interface capacity is paid for by all transmission customers whether or not they receive a benefit from the set-aside. In general, we believe that the latitude associated with CBM undermines the certainty and transparency that is needed for non-discriminatory, open-access transmission service.

160. The current *pro forma* OATT offers two means of reserving transfer capability, either of which implicitly provides some financial discipline to overreservations. The first is the requirement to designate a network resource on the other side of the interface and assume the associated financial responsibility of either owning the resource or executing a firm power purchase agreement. The other is to contract for firm point-to-point service on the interface, which requires the payment of a point-to-point reservation charge. In either case there is a disincentive to reserving transfer capability simply to prevent someone else from using it on a firm basis. With

[159] In this NOPR, we direct our guidance to NERC, though the reliability standards relating to ATC ultimately will be adopted by the ERO.

[160] We note that Commission staff recently released a preliminary assessment of the proposed ATC-related reliability standards, stating that they ''may result in unnecessary regional variations not justified by technical differences and inconsistent applications.'' Staff Preliminary Assessment of the North American Reliability Council's Proposed Mandatory Reliability Standards at 80 (May 11, 2006).

[161] For example, there are two primary ATC calculation methodologies: The contract path approach and the flowgate approach. *See generally* P 115. However, the ATC values that result from application of either method should largely be the same if consistent data inputs and modeling assumptions are used.

[162] As discussed further below, for consistency to be fully effective, it should be coupled with increased transparency. As such, we also propose greater transparency below.

[163] One approach models power transfers by scaling up/down the load, a second approach scales generation up/down, and yet another approach uses a combination of changes in load and generation.

[164] ''Appropriate reservations'' takes into account the time frame (*e.g.*, yearly, monthly) and ATC product (*e.g.*, firm, non-firm) being calculated.

[165] *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 FERC ¶ 61,099 (1999) (CBM Order).

[166] CBM Order at 61,237–38.

these processes in mind, the Commission has identified three possible options to provide the necessary certainty, transparency, and financial discipline necessary to remedy the potential for undue discrimination associated with inappropriate ATC set-asides for CBM. These options need not be mutually exclusive.

161. One option is to require that clear standards be developed for how the CBM value should be determined and allocated across transmission paths, and for which customers CBM should be used.[167] Consistent with the standards development process that is already in progress, we propose that these standards specify how CBM should be reserved to allow any load-serving entity to meet generation reliability criteria on a nondiscriminatory basis. In addition, we propose that NERC specify emergency generation deficiency conditions during which a load-serving entity will be allowed to use the transfer capability reserved as CBM. We believe that CBM should be reserved only when there is insufficient local generation capacity to meet generation reliability standards, and it should always have a zero value in the calculation of non-firm ATC.

162. Another approach may be to develop a specific charge for setting aside ATC for CBM. This approach would treat CBM as a service that would be available to customers serving load within the transmission provider's service area. To do this, the Commission would propose that an entity for which transfer capability has been set aside to meet generation reliability criteria be charged a separate rate for this service. We seek comment on this proposal to charge a separate rate, as well as comment on the potential impacts on overall rates and revenues. We also seek comment on whether there are credible situations in which the proposal would not be feasible. Commenters are encouraged to provide specific examples.

163. A third option may be to eliminate CBM and replace it with specific transfer capability reservations associated with designated network resources. In several cases, the Commission addressed instances when transmission providers had taken advantage of their ability to preserve interface capability to serve their own load while limiting the ability of competing suppliers to access customers on their systems. In these orders, the Commission position was that if a utility wanted to use firm transmission capacity on an interface to serve its native load, it was required to designate a network resource associated with that capacity on the other side of the interface pursuant to the requirements of the *pro forma* OATT.[168] Specifically, the Commission stated that the *pro forma* OATT requires the transmission provider to designate all network resources, including those acquired for the purpose of meeting generation reserves, in the same manner as network customers do.[169] The retention of this obligation would require the transmission provider to replace any existing set-aside of firm transfer capability as CBM with reservations for specific designated resources. We seek comment on the reasonableness of eliminating CBM and any impacts on the reliable operation of the transmission system. Commenters are encouraged to provide specific examples of transmission providers that currently do not use CBM and, alternatively, conditions under which CBM must be used. We also ask for comments on how eliminating CBM would affect the ability of load-serving entities to meet existing generation reliability adequacy requirements.

164. The Commission proposes that public utilities, working through NERC, develop clear standards for how TRM is determined, allocated across transmission paths, and used. In addition, we propose to require that the standards ensure that there will be no contingency double-counting when calculating TRM, TTC and CBM. We also propose that the standards developed should specify the uncertainties that are accounted for in TRM and the methods used to determine their impacts on TRM values. The Commission proposes that TRM can be used to accommodate uncertainties such as: (1) Load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, including intermittent resources, (6) automatic sharing of reserves, and (7) other uncertainties identified through the NERC forums.

165. The Commission acknowledges that accurate data and system models are essential to accurately simulate the performance of the electric system when calculating ATC. The data and models used by the transmission provider should be consistent, to the maximum extent practicable, with the data and models used for the planning, operation, and expansion of the transmission system. While NERC's current ATC-related standards (MOD–001—MOD–009) require that steady state and dynamic data be submitted and that steady state and dynamic system models be prepared, there is no requirement to periodically benchmark these models and appropriately modify them against actual system events.[170] Therefore, the Commission proposes that public utilities, working through NERC, modify the ATC-related standards to incorporate a requirement for the periodic review and modification of these models (including load flow base cases, short circuit data, transient and dynamic stability simulation data, contingency,[171] subsystem and monitoring files, and production cost models), in order to ensure that they are up to date.

166. Modeling assumptions are a crucial element in the calculation of ATC. The Commission proposes that public utilities, working through NERC, develop consistent assumptions for use in ATC determinations. The Commission proposes that the assumptions used in the calculation of ATC be made consistent among transmission providers, to the maximum extent practicable. In general, the Commission believes that the assumptions used in the determination of ATC should be consistent with those used when planning the operation and expansion of the transmission system. This is necessary to remedy the potential for undue discrimination between the manner in which a transmission provider plans and operates its system to serve native load and the manner in which it calculates ATC for service to third parties. Consequently, the models for short- and long-term ATC calculation should be developed using consistent assumptions regarding the load level, generation dispatch, transmission and generation facilities maintenance schedules, contingency outages and topology as those used in the planning for operation and expansion. In addition, the long-term ATC models should rely to the maximum extent practicable upon the

[167] NERC has already contemplated developing a standard to address CBM issues. *See http://www.nerc.com/~filez/standards/MOD-V0-Revision.html*.

[168] *See Aquila supra* note 121; *see also Morgan Stanley Capital Group* v. *Illinois Power Co.*, 83 FERC ¶ 61,204, *clarified*, 83 FERC ¶ 61,299 (1998), *order on reh'g*, 93 FERC ¶ 61,081 (2000).

[169] *Wisconsin Public Power Inc. SYSTEM* v. *Wisconsin Public Service Corp.*, 83 FERC ¶ 61,198 at 61,857–58 (1998).

[170] *See* U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, Recommendation Number 24 (April 2004). *See http://reports.energy.gov/*.

[171] Contingency files should contain information on special protection schemes and remedial action plans.

same assumptions regarding new transmission and generation facilities additions and retirements as those used in the planning for expansion.

167. More specifically, the Commission proposes to direct public utilities, working through NERC, to establish consistent assumptions that are related to the modeling of: (1) Representative load levels, (2) generation dispatch, (3) transmission reservations and (4) counterflows, in addition to any other modeling assumptions identified by NERC. Regarding the assumptions used for load level modeling in the ATC calculation, the Commission proposes to require all transmission providers to have a consistent approach to modeling of load levels. With respect to the base generation dispatch, we propose that public utilities, working through NERC, establish a method for determining which generators should be modeled in service, including guidance on how independent generation should be considered. With respect to modeling of particular transactions, the Commission believes that a consistent approach is needed on how to simulate power flows from points of receipt to points of delivery when sources are unknown. Accounting for transmission reservations in an ATC/AFC calculation also should be consistent.[172] We note that the purpose of more consistent modeling assumptions is to eliminate discretion and the potential for undue discrimination. This proposal is not intended to change the manner in which native load customers are served. We seek comment on whether (and, if so, how) this proposal would affect service to native load customers.

168. The Commission also supports the development of clear standards on how often ATC/AFC and its individual components are calculated and updated. The Commission proposes that public utilities, working through NERC and NAESB, develop standards requiring that the calculation be performed on a consistent time interval among transmission providers and in a manner that closely reflects the actual topology of the system concerning generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. The Commission also supports uniform updating of ATC values and components by adjacent control areas.

[172] Currently, one method models all appropriate reservations in the power flow base case model, when another models only those reservations that are expected to be scheduled, and accounts for others by decrementing flowgate AFC.

169. The Commission believes that significant improvements in the communication, coordination, and exchange of data across all transmission providers in an interconnection are needed to produce accurate determinations of ATC. Therefore, we propose that public utilities, working through NERC, develop consistent protocols that would enable and require the exchange of data among transmission providers. We propose that the following data, at a minimum, should be exchanged among transmission providers for the purposes of ATC modeling: (1) Load levels, (2) transmission planned and contingency outages, (3) generation planned and contingency outages, (4) base generation dispatch, (5) existing transmission reservations, including counterflows, (6) ATC calculation frequency, and (7) source/sink modeling identification. In addition, NERC may identify other data needs through the standards development process. We seek comment as to how much data sharing is workable; whether there are additional data that should be provided; whether access to such data should be limited to transmission providers; and if there are existing forums by which these or similar data are already shared.

170. In order to facilitate the process for achieving consistency in ATC calculations we have proposed in this NOPR, the Commission directs Staff to hold a technical conference. The technical conference will be transcribed to provide the Commission and NERC a record of the comments received at the conference. The Commission will provide further guidance regarding the date of the technical conference and the topics it intends to address at the technical conference in a subsequent notice.

Transparency

Pro forma OATT

171. Though the Commission's requirement that a transmission provider describe its ATC calculation methodology in its OATT has not changed, that requirement has been interpreted in various ways. Some transmission providers post a detailed explanation of how they calculate ATC, while other transmission providers post very general descriptions that fail to offer sufficient detail for third parties to understand how ATC has been derived. The Commission is concerned that the lack of transparency in some of the descriptions provided by transmission providers gives these transmission providers too much discretion to change ATC practices without sufficient oversight and review. The Commission also is concerned that this lack of transparency could allow transmission providers to unduly discriminate against their competitors when allocating transmission service. We agree with commenters that greater transparency is needed into how transmission providers calculate and allocate ATC. Accordingly, in order to ensure that transmission service is provided in a nondiscriminatory manner, we propose to require transmission providers to take certain measures to make their ATC calculation process more transparent. We believe that these proposed changes will give transmission customers access to sufficient information to be able to examine the integrity of the process. Moreover, our proposal for greater consistency in the way ATC is calculated should aid in transparency because there will be far fewer differences in the way individual transmission providers calculate ATC. This will make it less difficult to determine whether ATC is being calculated in an unduly discriminatory manner.

172. Specifically, we propose to require transmission providers to include, at a minimum, in Attachment C of their OATT, the following information concerning their ATC calculation methodology (including the calculation of AFC, if applicable). First, we propose to require transmission providers to state their specific mathematical algorithm used to calculate their firm and non-firm ATC (and AFC, if applicable) for their scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and their planning horizon (beyond the operating horizon). Second, we propose that transmission providers provide a process flow diagram that illustrates the various steps through which the ATC/AFC is calculated.

173. In addition, we propose to require transmission providers to include in Attachment C a detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons. Thus, for TTC, a transmission provider should: (1) Explain its definition of TTC; (2) explain its TTC calculation methodology (*e.g.*, load flow, short circuit, stability, transfer studies); (3) list the databases used in its TTC assessments; and (4) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

174. For ETC, we propose to require a transmission provider to explain: (1) Its definition of ETC; (2) the calculation methodology used to determine the transmission capacity to be set aside for native load and non-OATT customers; (3) how point-to-point service requests are incorporated; (4) how rollover rights are accounted for; and (5) its processes for ensuring that non-firm capacity is released properly (*e.g.*, when real time schedules replace the associated transmission service requests in its real-time calculations). With regard to (5), we seek comment on whether transmission providers currently are keeping track of when firm service reservations are not scheduled and should be released as non-firm.

175. If a transmission provider uses an AFC methodology to calculate ATC, we propose to require it to explain: (1) Its definition of AFC; (2) its AFC calculation methodology (*e.g.*, load flow, short circuit, stability, transfer studies); (3) its process for converting AFC into ATC; (4) what databases are used in its AFC assessments; (5) the assumptions used in its AFC assessments; and (6) the reliability criteria used for contingency outages simulation.

176. For TRM, we propose to require a transmission provider to explain: (1) Its definition of TRM; (2) its TRM calculation methodology (*e.g.*, its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (3) the databases used in its TRM assessments; (4) the conditions under which the transmission provider uses TRM; and (5) the process used to prevent double-counting of contingency outages used in its TTC and TRM calculations. We propose to require transmission providers that do not reserve TRM to reflect that in Attachment C. We seek comment on the above proposal, specifically on what type of showing a transmission provider could make with regard to the process used to prevent double-counting.

177. Furthermore, in the CBM Order, the Commission required transmission providers to post a specific and self-contained narrative explanation of their CBM practices, including who performs the assessment (transmission or merchant staff), the methodology used to perform generation reliability assessments (*e.g.*, probabilistic or deterministic), whether the assessment method reflects a specific regional practice, the assumptions used in those assessments and the basis for the selection of paths on which CBM is set aside. In addition, the Commission directed transmission providers to post their procedures for allowing CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). The Commission further stated that if a utility's practice was not to reserve CBM, it should reflect that in Attachment C. We propose to require transmission providers to include this narrative in Attachment C of their OATTs.

178. In addition, for CBM, we propose to require a transmission provider to: (1) Explain its definition of CBM; (2) list the databases used in its CBM calculations; and (3) prove that there is no double-counting of contingency outages when performing CBM calculations.

179. Though we are proposing to require transmission providers to provide greater clarity in the description of their ATC calculations, it is our expectation that the reforms we propose for greater consistency of ATC methods will minimize the burden on transmission providers and customers of assessing various ATC calculation methodologies. Ultimately, when the ATC standards development process we propose is completed, we expect that Attachment C will refer to the NERC standards and will differ by transmission provider only with respect to the limited elements of the ATC calculation that may not have been made consistent.

OASIS

180. The Commission's existing regulations require certain ATC-related information to be posted on each transmission provider's OASIS, while other information is required to be provided on request. To ensure that relevant information is available on a timely basis to all market participants, we propose to amend our regulations to allow potential customers greater access to information that will enable them to obtain service on a non-discriminatory basis from any transmission provider.[173] We believe that our proposed reforms will not only enhance the amount and accuracy of information available to customers, but will also increase the ability of the Commission and others to detect any potentially unduly discriminatory behavior in a transmission provider's calculation and allocation of ATC.

[173] *See* 18 CFR 37.2 (2005).

181. Our regulations state that a transmission provider's [174] ATC and TTC calculations shall be performed according to consistently applied methodologies referenced in the transmission provider's OATT and shall be based on current industry practices, standards and criteria.[175] We propose to revise this provision to include compliance with the reliability standards developed by the ERO—*i.e.*, ATC and TTC calculations shall be performed according to consistently applied methodologies referenced in the transmission provider's OATT and shall be based on the ERO reliability standards as well as current industry practices, standards and criteria.

182. The regulations further state that, on request, a transmission provider must provide all data used to calculate ATC and TTC for any constrained paths.[176] Transmission providers also are required to make any system planning studies or specific network impact studies performed for customers to determine network impacts publicly available on request and to post a list of such studies on the OASIS.[177] The Commission proposes to maintain these requirements.

183. The Commission's OASIS regulations require transmission providers to calculate and post ATC and TTC for each posted path.[178] The regulations define two classes of posted paths based on usage: ''constrained'' and ''unconstrained.'' A constrained posted path is any posted path for which ATC has been less than or equal to 25 percent of TTC at any time during the preceding 168 hours or is calculated to be less than, or equal to, 25 percent of TTC for any period during the current hour or the next 7 days. An unconstrained posted path is any posted path that is not a constrained posted path.[179] The Commission proposes to amend the regulations relating to the data posted for constrained posted paths, but largely to retain the existing

[174] We note that various provisions of the OASIS regulations use the term ''Responsible Party,'' which means the transmission provider or an agent to whom the transmission provider has delegated the responsibility of meeting any of the requirements of the regulations. For simplicity, however, we will use the term ''transmission provider'' here.

[175] *See* 18 CFR 37.6(b)(2)(i) (2005).

[176] *See* 18 CFR 37.6(b)(2)(ii) (2005).

[177] *See* 18 CFR 37.6(b)(2)(iii) (2005).

[178] *See* 18 CFR 37.6 (2005).

[179] *See* 18 CFR 37.6(b)(1)(iii) (2005). Our regulations require transmission providers to post ATC and TTC for specific time horizons for constrained posted paths and unconstrained posted paths. The Commission proposes to maintain the existing time horizons. *See* 18 CFR 37.6(b)(3)(i)–(ii) (2005).

posting requirements for unconstrained posted paths, as set forth below.

184. First, in the CBM Order, the Commission required transmission providers, with respect to each path for which the utility already posts ATC, to post (and update) the CBM figure for that path. The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS. The Commission proposes to incorporate these CBM posting requirements into its regulations.

185. With respect to paths for which the utility already posts ATC, TTC, and CBM, we further propose to require each transmission provider to also post (and update) the TRM value for that path.

186. Our existing regulations require ATC and TTC on constrained paths to be updated when: (1) Transactions are reserved, (2) service ends, or (3) whenever the TTC estimate for the path changes by more than 10 percent. We do not believe that this regulation has resulted in sufficient information to determine why ATC values changed. To provide a transmission customer with useful information to assist with its evaluation of monthly and yearly firm transmission service options, we propose to supplement the existing regulations by requiring the transmission provider to post a brief, but specific, narrative explanation of the reason for the posted change in the monthly and yearly ATC values on a constrained path. This narrative would describe, for example: (1) Scheduling of planned outages and occurrence of forced transmission outages; (2) de-ratings of transmission facilities; (3) scheduling of planned generation outages and occurrence of forced generation outages; (4) changes in load forecast, (5) changes in new facilities in-service dates, or other events or assumption changes that cause the ATC value to change. We seek comment on whether the posting of this new information would provide adequate transparency to the customer on a frequent enough basis without imposing an undue burden on the transmission provider. We seek comment on whether a similar narrative also should be required when ATC remains unchanged at a value of zero for some specified period of time.

187. We propose to maintain the requirement in 18 CFR § 37.6(e)(2)(i) that a transmission provider must post the reason for a denial of a request for service. We propose, however, to amend this provision to require a transmission provider to maintain and make available information supporting the reason for the denial for five years. In addition, we propose to extend the time period for which transmission providers must maintain transmission service information for audit. Our regulations currently require audit data to be retained and made available upon request for download for three years from the date when they are first posted.[180] We propose to change the period from three to five years.

188. In the CBM Order, the Commission stated that the level of ATC set aside for CBM can and should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized). Thus, the Commission directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the availability of CBM and to post on OASIS their practices in this regard. We propose to incorporate these requirements in the Commission's regulations and to obligate transmission providers to reevaluate the CBM set aside at least quarterly.

189. We also propose to require the transmission provider and network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of a network resource. As with other transmission request information posted on OASIS, the transmission provider should keep designation and termination information posted on OASIS for 90 days and should make designation and termination information available upon request for five years, consistent with 18 CFR 37.7(b) (2005). Transmission customers will be able to query requests to designate and terminate a network resource under 18 CFR 37.6(a)(6)(2005). We propose to require the transmission provider to post on its OASIS a list of its current designated network resources and all network customers' current designated network resources. The list of network resources should include the name of the resource, its geographic and electrical location, and the amount of capacity from the unit to be designated as a network resource.

190. Finally, we remind transmission providers that transfer capability associated with transmission reservations that are not scheduled in real time must be included in non-firm ATC and posted on OASIS.[181]

[180] *See* 18 CFR 37.7(b) (2005).

[181] Our regulations require non-firm ATC and TTC for constrained posted paths to be posted in the same manner as firm ATC and TTC, except that monthly and seasonal capability need only be posted if requested. *See* 18 CFR 37.6(b)(3)(i)(B)(2005).

CEII

191. Shortly after the attacks on September 11, 2001, the Commission removed from public viewing certain documents that were likely to contain detailed specifications of critical infrastructure facilities. CEII is information concerning proposed or existing critical infrastructure (physical or virtual) that: (1) Relates to the production, generation, transportation, transmission, or distribution of energy; (2) could be useful to a person in planning an attack on critical infrastructure; (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552 (2000); and (4) does not simply give the location of the critical infrastructure. Accordingly, access to transmission-related information collected by the Commission has been restricted by the Commission's CEII regulations. Thus, for example, information filed in FERC Form No. 715 (including base case power flow data and transmission system maps) as well as system planning and network impact studies and models are no longer publicly available. However, requesters with a particular need (such as transmission customers and consultants with legitimate needs) have the opportunity to access information designated as CEII from the Commission by submitting a request to the Commission under the procedures set forth in our regulations. In Order No. 643,[182] the Commission addressed situations in which its regulations require public utilities to disclose information directly to the public. The Commission ruled that potential CEII disclosed directly from the public utility to the public should be evaluated under the same rules addressing the disclosure of CEII from the Commission to the public, *i.e.*, if an entity concludes that certain of its information is CEII, it must designate it as such and provide other specified information about obtaining access to the CEII through the Commission's process. The Commission also held that it did not intend to restrict an entity's ability to reach appropriate arrangements for sharing CEII, and that all persons with a legitimate need for CEII should be able to gain access to it with a minimum of difficulty.[183]

192. We believe that much of the information we propose to require transmission providers to provide in this proposed rulemaking will not pose CEII concerns. If commenters believe

[182] *Amendments to Conform Regulations with Order No. 630,* Order No. 643, 68 FR 52089 (Sep. 2, 2003), FERC Stats. & Regs. ¶ 31,149 (2003).

[183] *Id.* at P 16.

that any of the information is CEII, they should explain the basis for that view. We recognize that requiring interested persons to use the existing CEII process to access information we propose to require transmission providers to provide in this rulemaking could undermine our goal of providing increased transparency to information necessary to evaluate the use of the transmission system. As a result, we seek comment on procedures that could be adopted by transmission providers to streamline the resolution of CEII concerns and allow timely disclosure of information from the transmission providers to interested persons.

Additional Data Posting

193. Notwithstanding our proposed reforms requiring greater consistency of and increased transparency into ATC calculation methodologies, certain aspects of ATC calculation may remain committed to the discretion of the transmission provider. Thus, we believe that additional reporting requirements may be necessary to detect undue discrimination. Accordingly, we propose to add a requirement in our regulations for transmission providers to post on OASIS certain metrics related to the provision of transmission service under the *pro forma* OATT. Specifically, we propose to require transmission providers to post data each month concerning transmission service requests associated with particular paths or flowgates that would clearly identify the number of requests that have been accepted and the number of requests that have been denied during the prior month. The posted data would show: (1) The number of non-affiliate requests for transmission service that have been rejected and (2) the total number of non-affiliate requests for transmission service that have been made. This posting would distinguish between the length of the service request (*e.g.*, short-term or long-term requests) and between the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). We also propose that the transmission provider post similar information for affiliate transactions. In other words, the transmission provider would also post: (1) The number of affiliate requests for transmission service that have been rejected, and (2) the total number of affiliate requests for transmission service that have been made. Similarly, this posting would distinguish between the length of the service request (*e.g.*, short-term or long-term requests) and between the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service).

194. Another area of discretion is the load forecasts used by the transmission provider when computing ATC. The Commission recognizes that the lack of transparency regarding transmission providers' forecasted and actual use of the transmission system makes it difficult to determine whether an appropriate amount of capacity is being set aside for service to native load. To address this concern, we are considering additional posting requirements. For example, should transmission providers make available their underlying load forecast assumptions for all ATC calculations? In addition, should transmission providers post, on a daily basis, their actual daily peak load for the prior day? We believe that this posting of forecasted and actual loads would allow the Commission and others to make a meaningful comparison of these elements. We invite comment on whether this information would be helpful for such a comparison. We also seek comment on the overall benefits of posting metrics and on potential alternative metrics.

195. For all of our proposed OASIS reforms, we propose to require public utilities, working through NAESB, to develop standards for consistent methods of posting the new requirements on OASIS so that a common format is used.

B. Transmission Planning—Coordinated, Open and Transparent Planning

196. Order No. 888 set forth certain minimum requirements for transmission system planning. For example, the *pro forma* OATT requires transmission providers to plan for the transmission needs of their network customers on a comparable basis (section 28.2), and it requires them to expand their systems to accommodate firm point-to-point customer requests (sections 13.5 and 15.4) that cannot be satisfied due to transmission constraints or satisfied more economically via redispatch. In addition, in Order No. 888–A, the Commission encouraged utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable. The Commission also encouraged regional planning so that the needs of all participants are represented in the planning process.[184] However, the Commission did not require joint planning between transmission providers and their customers or between transmission providers in a given region,[185] nor did it impose any specific requirements regarding the manner in which transmission providers should coordinate their transmission system planning with their *pro forma* OATT customers. The only section of the *pro forma* OATT that directly speaks to joint planning is section 30.9, which provides that for facilities constructed by a network customer, the network customer must receive credit where such facilities are jointly planned and installed in coordination with the transmission provider.[186]

197. In the NOI, the Commission asked several questions about joint planning between transmission providers and their customers. For example, we asked whether joint planning should be made mandatory, particularly when transmission requests affect adjacent transmission systems. We also inquired whether joint planning should be subject to an annual reporting requirement or audits. Additionally, we asked for comment on a number of issues designed to determine whether any *pro forma* OATT reforms are necessary to ensure that the transmission system is expanded so that customers have adequate transmission service. As the comments below indicate, commenters generally all believe that joint and regional planning are necessary and desirable, but there is a split over whether it should continue to be voluntary or should be made a requirement.

Comments Supportive of Mandatory Joint and Regional Planning

198. A number of commenters contend that joint planning between transmission providers and their customers should be required by the *pro forma* OATT. Most of these commenters also advocate joint planning among transmission providers in a given region. In perhaps the strongest comments on the topic, TDU Systems and TAPS request that the Commission mandate an open, regional transmission expansion planning process that provides opportunities for transmission customers to join and participate in the planning process. Many other commenters also support joint and regional planning in some form or

[184] *See* Order No. 888–A at 30,311.

[185] *See id.*

[186] *Pro forma* OATT section 21.2, ''Coordination of Third-Party System Additions,'' provides for certain rights for transmission providers to coordinate construction of facilities on their systems associated with point-to-point customer requests and related construction on a third-party transmission system, but imposes no obligation on transmission providers.

another, with some focusing particularly on requiring such planning when adjacent transmission systems are affected.[187] Bonneville and Williams also assert that there is already Commission precedent for joint planning in our procedures on large generator interconnections, which require the coordination of studies when interconnection requests affect other systems. EPSA states that the Commission should require that neighboring systems formalize the process under which broad regional models are developed and used to study requests on any system within a broadly defined region. Powerex points out that the lack of regional transmission planning is one of the most difficult issues faced in the Pacific Northwest, and PPL asserts that transmission planning and expansion in the Western Interconnection does not support a competitive market.

199. In addition, many commenters contend that transmission providers should be required to report on an annual basis the joint and regional planning that has occurred or been requested.[188] TAPS states that an annual filing notice by the Commission that gives the public an opportunity to comment should be buttressed with audits, in order to ensure that transmission providers are taking joint planning with their network customers (and neighboring systems) seriously. EPSA likewise contends that transmission providers should be required to report to the Commission on an annual basis the joint planning that has occurred or been requested on their systems, and that the Commission should conduct audits to determine the level of compliance with any joint planning requirement or agreement.

200. The commenters that advocate mandatory joint and regional planning assert that it is needed because transmission providers unduly discriminate against their customers when planning their transmission systems. For example, a number of commenters assert that transmission providers meet their own needs for transmission planning and construction before (and often without) meeting those of their customers.[189] NRECA asserts that since the implementation of Order No. 888, a number of public utility transmission providers—despite clearly stated obligations in the *pro forma* OATT—have not planned for their load-serving transmission customers on a basis comparable to that of their own bundled retail native load. TDU Systems believes that joint and regional transmission planning is a critical component of ensuring comparability between a transmission provider's use of the transmission system and a network customer's use of the transmission system, largely because transmission providers have an incentive to thwart the expansion planning process. Both NRECA and TDU Systems argue that the planning processes in RTOs and ISOs also are insufficient because they often only allow customer input after transmission plans are developed by individual transmission providers.

201. TAPS asserts that the absence of joint planning has resulted in unduly discriminatory transmission service. For comparable service to be a reality, TAPS asserts that the transmission system must be planned and built for customer needs, just as it must be planned and built to meet the transmission providers' need to provide service to their native loads. Old Dominion contends that transmission providers often locate transmission in such a way that it favors their own generation. According to Lafayette, transmission providers have increased their generation dominance by inadequately planning for the needs of their transmission customers so that they are unable to turn to alternative suppliers. East Texas Cooperatives also argues that some transmission providers continue to plan their systems in isolation from the needs of other load-serving entities. EPSA concludes that the transmission needs of non-transmission provider customers are simply not integrated effectively into the planning process. APPA notes that the original goal of the *pro forma* OATT—an inclusive planning process that takes into account on a comparable basis the load growth and new generation resource needs of all loads served using the transmission provider's system—has not been achieved. Many commenters assert that joint and regional transmission planning is necessary in order to ensure adequate infrastructure development.[190] Others focus on the need for joint and regional planning to address the fact that changes on one system often affect transmission service on adjacent systems.[191] Lastly, APPA blames substantial and rising congestion costs on inadequate transmission planning, and EPSA contends that better transmission planning is needed to support a competitive electricity market.

Comments Supportive of Voluntary Joint and Regional Planning

202. Another large group of commenters, including many investor-owned utilities, stress that joint and regional planning, while laudable, should not be mandatory and that it should continue to be voluntary or that processes are already in place to encourage regional planning.[192] Progress Energy, for example, contends that there are several formalized processes in place today that foster joint and regional planning, such as the process in North Carolina. Southern points out that in addition to participating in Southeastern Electric Reliability Council (SERC) planning activities, it is engaged in other types of joint regional planning (*e.g.*, through the Georgia Integrated Transmission System (Georgia ITS)).[193] Nevada Companies supports the approach already used in the WECC, which employs interconnection-wide models for planning. Nevada Companies explains that these studies are then made available to all other WECC transmission providers. In addition, APS, Tacoma, and WAPA point to numerous forums (*e.g.*, the Southwest Area Transmission planning group and the Southwest Transmission Expansion Plan process) where transmission providers and other industry stakeholders coordinate their transmission plans. LPPC also states that the Georgia ITS has provided benefits to participants and the region—in the form of improved investment in infrastructure and through the introduction of new sources of capital.

[187] *E.g.*, AEP, Alcoa, APPA, Bonneville, Calpine, EPSA, Lafayette, National Grid, NCPA, NRECA, Old Dominion, Trans-Elect, Williams, and Xcel. Though it does not generally support mandatory joint and regional planning, EEI recommends that the Commission modify the *pro forma* OATT to address planning when transmission requests require upgrades on or otherwise adversely affect adjacent transmission systems.

[188] *E.g.*, East Texas Cooperatives, EPSA, FMPA, MidAmerican, and TAPS.

[189] *E.g.*, FMPA, Midwest Municipals, NCPA, and NRECA.

[190] *E.g.*, AEP, Calpine, Constellation, East Texas Cooperatives, ELCON, NRECA, and TransAlta.

[191] *E.g.*, Alcoa and EPSA. EEI acknowledges the planning difficulties that arise when a transmission request on one system causes the need for upgrades to another system.

[192] *E.g.*, Cinergy, Entergy, KCP&L, LPPC, MidAmerican, Nevada Companies, North Carolina Commission, Northwestern, PNM–TNMP, Progress Energy, Salt River, Snohomish, South Carolina Regulatory Staff, Southern, Tacoma, and WAPA. Nevertheless, KCP&L, Nevada Companies, and Progress Energy join with EPSA in calling for a more formalized process for addressing base case and expansion plans.

[193] Georgia ITS consists of jointly-owned transmission facilities, which are owned by the Southern subsidiary Georgia Power, the Municipal Electric Authority of Georgia, the Georgia Transmission Corporation—a cooperative utility—and Dalton Utilities—a municipal system.

Lastly, some commenters point out that collaborative regional planning already occurs in RTO and ISO regions.[194] With regard to PJM, however, TDU Systems argues that better transmission planning is required due to PJM's ''rubber-stamping'' of transmission provider identified transmission upgrades. Exelon states that the Northeastern ISO/RTO Planning Coordination Protocol is a formal agreement, executed in 2004, among the PJM Interconnection, the New York Independent System Operator, and ISO New England, pursuant to which the three organizations conduct a comprehensive process of coordinating system planning activities.

203. With regard to the imposition of reporting requirements, many commenters argue that transmission providers already are required to report joint planning activities.[195] EEI, for example, contends that joint planning activities under section 30.9 of the *pro forma* OATT currently are required to be reported on each transmission provider's OASIS. EEI argues that audits should not be required. Bonneville contends that, at least in the Pacific Northwest, annual reporting and audits are not needed. Bonneville states that transmission planning staffs already bear a heavy workload; for example, Bonneville's planning staff must address many requests for transmission and interconnection service, as well as conduct regional planning efforts and comply with regional and national reliability initiatives. Northwestern states that reporting requirements or audits are not needed and would be burdensome to the transmission provider, distracting it from performing its joint planning responsibilities.

Current pro forma OATT Planning Responsibilities

204. Order No. 888 and the *pro forma* OATT require that transmission providers plan and upgrade their transmission systems to provide comparable open access transmission service for their transmission customers. For example, with regard to network service, section 28.2 of the *pro forma* OATT provides that the transmission provider ''will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System.'' Section 28.2 also provides that the Transmission Provider shall, consistent with Good Utility Practice, ''endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.''

205. The *pro forma* OATT also requires that new facilities be constructed to meet the service requests of long-term firm point-to-point customers. Section 13.5 of the *pro forma* OATT requires the transmission provider to consider redispatch of the system to relieve any constraints that are inhibiting a transmission customer's point-to-point service if it is economical to do so; but if redispatch is not economical, the transmission provider is obligated to expand or upgrade its system. This expansion obligation on the part of the transmission provider for point-to-point service is found in section 15.4 of the *pro forma* OATT, which provides that when a transmission provider cannot accommodate a point-to-point transaction because of insufficient capability on its system, it will ''use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service.'' Section 15.4 goes on to provide that ''the Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities.'' Importantly, however, the transmission provider's obligation to upgrade or expand its system to provide point-to-point service as detailed in section 15.4 is contingent on the transmission customer agreeing to compensate the transmission provider for such costs pursuant to the terms of section 27 (providing for cost responsibility for upgrades and/or redispatch ''to the extent consistent with Commission policy''). Order No. 888 does not, however, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans.[196]

The Need for Reform

206. As discussed more fully in Part III.C above, in the ten years since Order No. 888 was issued, the Nation has witnessed a decline in transmission investment relative to load growth. As a result, transmission capacity per MW of peak demand has declined in every NERC region, and it has been estimated that capital spending must increase significantly to ensure system reliability and to accommodate wholesale electric markets. Many have argued that inadequate expansion of the transmission grid has contributed to the widespread transmission constraints that plague most regions of the country, as reflected in the limited amounts of ATC posted in many regions, increased frequency of denied transmission services requests, and increasingly common transmission service interruptions or curtailments, all of which make it more difficult for transmission customers to transfer power. In short, it has become clear that since Order No. 888 was issued, the Nation's transmission grid has not been planned and developed adequately and projections suggest that without reform this trend will continue.

207. The need for transmission planning reform also has been recognized by the Consumer Energy Council of America (CECA), a public interest energy policy organization with a 30-year history of bringing stakeholders together to find solutions to contentious energy policy issues. CECA launched its Transmission Infrastructure Forum in early 2004,[197] which published its conclusions in January 2005 in a final report titled ''Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability'' (CECA Report).[198] Among other things, the CECA Report concludes that regional transmission planning with consumer input early in the process is needed to ensure the development of a robust transmission system capable of meeting consumer needs reliably and at

[194] *E.g.*, Ameren, CAISO, Exelon, ISO New England, and MidAmerican.

[195] *E.g.*, Bonneville, EEI, KCP&L, PNM–TNMP, Salt River, Tacoma, and WAPA.

[196] Certain transmission data is required to be provided annually in the FERC Form 715 (*e.g.*, Part 2—Power Flow Base Cases, Part 3—Transmitting Utility Maps and Diagrams, Part 4—Transmission Planning Reliability Criteria, Part 5—Transmission Planning Assessment Practices, and Part 6—Evaluation of Transmission System Performance). As discussed below, we do not believe that the FERC Form 715 reporting requirements have satisfied the need for transparency with regard to transmission planning.

[197] The CECA Transmission Infrastructure Forum included representatives from such diverse constituencies as investor-owned utilities, rural electric cooperatives, municipal power systems, federal power systems, independent power producers, equipment manufacturers, the U.S. Congress, the Commission, the U.S. Department of Energy, state legislatures, state public utility commissions, state energy offices and consumer advocates, consumer and environmental organizations, independent consultants, and academic institutions.

[198] Available at *http://www.cecarf.org/Publications/PublicationsAllDate.html.*

reasonable cost over time. The CECA Report stresses that regional transmission planning must address inter-regional coordination, the need for both reliability and economic upgrades to the system, as well as critical infrastructure to support national security and environmental concerns.[199]

208. Transmission providers have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. As the Commission noted in Order No. 888, ''[i]t 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.'' [200] This statement continues to be true today. In upholding the Commission's authority to require open access in Order No. 888, the court in *TAPS* v. *FERC* noted that ''[u]tilities that own or control transmission facilities naturally wish to maximize profit. The transmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers.'' [201] Thus, even when transmission providers do address congestion, they have an incentive to do so in a manner that benefits their own generation or loads rather than the generation or loads of their competitors. These disincentives frustrate new investment that could remedy both ''local'' congestion (*i.e.*, within the transmission provider's control area) and congestion between control areas, as well as remedy undue discrimination and increase bulk power trade. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.

[199] *See, e.g.*, CECA Report at 10–11.

[200] Order No. 888 at 31,682.

[201] 225 F.3d at 684; *see also New York* v. *FERC*, 535 U.S. at 8–9 (addressing Order No. 888's open access requirements, the Court noted that ''public utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions.'') (citation and footnote omitted).

209. The existing *pro forma* OATT does not adequately address the above-referenced problems. As noted, there is no general requirement that a transmission provider coordinate its transmission planning with customers, market participants, or its interconnected neighbors.[202] Additionally, though the *pro forma* OATT does require transmission providers to plan for the needs of their network customers and to expand their systems to provide service to point-to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions. Rather, the transmission provider currently is allowed to create its own transmission plan with limited or no input from affected market participants or other affected entities, such as state commissions. There is also no requirement that the planning process be transparent. While we recognize that certain planning information is required to be filed annually in FERC Form No. 714—Annual Electric Control and Planning Area Report and FERC Form 715—Annual Transmission Planning and Evaluation Report, this does not appear to provide sufficient transparency to remedy the remaining concerns expressed in this proceeding about the potential for undue discrimination in planning.

210. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no input into whether a particular plan treats all loads and generators comparably. Without sufficient transparency, market participants have no means to determine whether the plan developed by the transmission provider in isolation is discriminatory. Moreover, the process is inefficient. Disputes over discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning. The Commission has a duty to prevent undue discrimination in the rates, terms, and conditions of public utility transmission service, and therefore, an obligation to remedy these transmission planning deficiencies. The Commission's authority to remedy undue discrimination is broad.[203] In addition, new section 217 of the FPA requires the Commission to use its FPA authorities in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. Finally, we note that a more transparent and coordinated regional planning process can support the DOE's responsibilities under EPAct 2005 section 1221 to study transmission congestion and issue reports designating National Interest Transmission Corridors.

[202] As discussed more fully in Part V.C.2, section 30.9 of the current pro forma OATT may inhibit coordinated planning by making transmission providers reluctant to engage in coordinated planning, because of the requirement to give customers credits for jointly planned facilities. We are proposing to sever the link between credits and planning, and treat the two issues separately within the *pro forma* OATT.

211. We are encouraged that since the adoption of open access in Order No. 888, a number of voluntary coordinated and regional planning efforts have been developed throughout the country, including those administered by RTOs and ISOs. For example, each of the Commission-approved RTOs in the Northeast, Midwest and Southwest, as well as CAISO, provide for a coordinated and regional planning process with stakeholder input from each industry segment. The Commission also notes that there are several other promising efforts to establish voluntary coordinated and regional planning efforts around the country. For example, WECC is in the process of expanding its reliability responsibilities to include comprehensive transmission planning to address the regional economic transmission needs of its members and other stakeholders in its regional footprint. In addition, each of the subregions in WECC has a coordinated transmission planning process that, in varying degrees, is open to market participants and, in some instances, has resulted in significant new transmission being built on a joint ownership basis. In North Carolina, Duke, Progress Energy, and two other organizations—North Carolina Electric Membership Corporation and ElectriCities of North Carolina, Inc.—have endeavored to create and implement a collaborative electric transmission planning process in that state. This process provides for broad stakeholder input as well an independent facilitator. Other models

[203] *See* Order No. 888 at 31,669 (noting that the FPA ''fairly bristles'' with concern for undue discrimination (citing *Associated Gas Distributors* v. *FERC*, 824 F.2d 981, 998 (D.C. Cir. 1987)).

for coordinated planning include the Georgia ITS and joint ownership arrangements like it around the country.

212. We fully support these voluntary efforts and believe they are consistent in significant respects with the nature of the reforms we are proposing for transmission planning under the *pro forma* OATT. In those regions and subregions that already have adopted significant reforms, our proposal may require only modest changes, while other regions and subregions may need to undertake more significant changes to the way in which the transmission system is planned today.

213. Today, numerous competing interests have a need to utilize the transmission grid, and yet in many areas of the country that grid is planned much the same way as it was before the electric industry matured into a regional business and Order No. 888 was implemented. That is, the same public utilities that own and control the grid also control the planning process that governs when and how the grid is expanded and upgraded. In short, the transmission grid is being utilized in a fundamentally different way, consistent with the intent of open access, and a decade of experience has shown us that in order to remedy undue discrimination, the existing provisions of the *pro forma* OATT respecting transmission system planning must be reformed. Accordingly, in order to provide for more comparable open access transmission service, eliminate the potential for undue discrimination and anticompetitive conduct, and satisfy our statutory responsibilities under section 217 of the FPA, we propose that each public utility transmission provider participate in an open and transparent local and regional planning process that addresses certain fundamental principles of transmission planning. As we indicated above, existing regional planning processes will be expected to meet or exceed the transmission planning principles we outline in this proposed rule.

Coordinated, Open, and Transparent Transmission Planning

214. In order to eliminate the potential for undue discrimination as described above, and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we propose to amend the *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. We propose to require each public utility transmission provider to submit, as part of its compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the following coordinated and regional planning principles.[204] In the alternative, transmission providers may make a compliance filing in this proceeding describing their existing coordinated and regional planning process and showing that it is consistent with or superior to the requirements set forth below. Moreover, we expect municipal, cooperative, and other public power entities to participate in these processes as well, consistent with their obligation to provide reciprocal transmission service as detailed in Order No. 888. An open and transparent regional planning process cannot succeed unless all transmission owners participate.

Under our proposal in this NOPR, a coordinated, open and transparent process must satisfy the following eight principles:

1. *Coordination*—The transmission provider must meet with all its transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis. The Commission seeks comment on specific requirements for this coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features deemed important by commenters.

2. *Openness*—Transmission planning meetings must be open to all affected parties (including all transmission and interconnection customers, and state commissions). The Commission seeks comment on whether there are any circumstances under which participation should be limited, *e.g.*, to address confidentiality concerns.

3. *Transparency*—The transmission provider is required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its transmission system plans. The Commission seeks comment on whether the information provided in FERC Form 715 is adequate and, if not, what additional detail should be provided. The Commission also seeks comment on the format for disclosure, including protections to address confidentiality concerns.

4. *Information Exchange*—Network transmission customers are required to submit information on their projected loads and resources on a comparable basis (*e.g.*, planning horizon and format) as used by transmission providers in planning for their native load; and point-to-point customers are required to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. The Commission seeks comment on whether specific requirements should be adopted for this information exchange.[205] The transmission provider must allow market participants the opportunity to review and comment on draft transmission plans.

5. *Comparability*—After considering the data and comments supplied by market participants, the transmission provider is to develop a transmission system plan that: (1) Meets the specific service requests of its transmission customers; and (2) otherwise treats similarly situated customers (*e.g.*, network and retail native load) comparably in transmission system planning.

6. *Dispute Resolution*—The transmission provider must propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third-party neutral. The Commission's Dispute Resolution Service is available to assist transmission providers in developing a dispute resolution process. In addition to informal dispute resolution, affected parties would have the right to file complaints with the Commission under FPA section 206. The Commission seeks comment on whether any specific dispute resolution processes should be required.

7. *Regional Participation*—In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, the transmission provider is required to coordinate with interconnected systems to: (1) Share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data, and (2) identify system enhancements that could relieve ''significant and recurring'' transmission congestion (defined below). The Commission strongly encourages that such coordination encompass as broad a region as possible, given the interconnected nature of the transmission grid and the efficiency of addressing these issues in a single forum. The Commission also recognizes that, as in the West, it may be appropriate to organize regional planning efforts on both a subregional

[204] The revised *pro forma* OATT reflects the proposed planning requirement in sections 15.4, 16.1, 17.2(x), 28.2, 29.2, 31.6, and Attachment K.

[205] For network service, some of this information already is required by sections 29, 30 and 31 of the *pro forma* OATT, but to the extent it is not, we propose to require customers to provide additional information as necessary for the transmission provider to develop a system plan.

and regional level. The Commission seeks comment on whether there are existing institutions (such as the NERC regional councils or subregional planning groups) that are well situated to perform or coordinate this function.

8. *Congestion Studies*—The transmission provider is required annually to prepare studies identifying ''significant and recurring'' congestion and post such studies on its OASIS. The studies should analyze and report on the location and magnitude of the congestion; possible remedies for the elimination of the congestion, in whole or in part; the associated costs of congestion; and the cost associated with relieving congestion through system enhancements (or other means). The Commission seeks comment on how to define ''significant and recurring'' congestion, such as by reference to generation redispatch, repeated denials of service requests, zero ATC, frequent curtailments or a combination of these factors. The required congestion studies would address both ''local'' congestion (*i.e.*, within the transmission provider's system) and congestion between control areas and subregions. The purpose of this requirement is to ensure that affected market participants, state commissions, and this Commission understand both the costs of recurring transmission congestion and the remedies. The Commission seeks comment on how this information should be used by the transmission provider and market participants to address significant and recurring congestion.

215. The Commission encourages the use of an independent third party to oversee or coordinate the planning process. The Commission is not proposing to require an independent third party to control the process, but does believe that independence can provide greater confidence in the planning process and resulting studies. Independence can take many forms, from having an independent entity resolve disputes over planning assumptions and decisions (as in an RTO) to having an independent consultant coordinate and otherwise perform the annual congestion studies referred to above. The Commission seeks comment on the levels of independence that can provide benefits and the institutions that could offer such independence, such as whether Regional Entities under the ERO could provide such independence.

216. Additionally, the Commission strongly encourages the participation of state commissions and other state agencies, particularly with regard to regional planning, in the coordinated transmission planning processes being proposed in this NOPR. The participation and support of state commissions and other state agencies is important because state commissions regulate the cost of transmission that is included in bundled retail rates and states also perform transmission siting. Many states also have traditionally been involved in utility planning in some way for their state or region. The Commission seeks comment on how best to accommodate effective state participation.

217. The Commission seeks comment on several aspects of this proposal. First, the Commission seeks comment on how much flexibility each transmission provider in a region should be given in implementing any principles adopted. Second, the Commission seeks comment, by way of examples, on transmission planning processes that comply with the proposed transmission planning reforms in principle.

218. Third, we seek comment on whether there are other principles or requirements that should be adopted to support the construction of needed new infrastructure and otherwise ensure that all market participants are treated on a comparable basis. For example:

a. We seek comment on whether there should be a principle or guideline to govern the recovery and allocation of costs associated with funding the regional planning requirement. To devote the resources necessary to support an open and transparent regional planning process, we recognize that the participating entities must be assured of recovery of their costs, as well as assured that the costs will be borne equitably by all parties benefiting from the process.

b. We seek comment on whether there should be a requirement that, at least for large new transmission projects (such as new regional backbone facilities), there be an open season to allow market participants to participate in joint ownership of these projects. We believe that such a requirement could stimulate more investment in the grid and ensure that all customers have the ability to participate in new projects on a nondiscriminatory basis, including smaller market participants that cannot support the construction of large new facilities on their own.[206] We seek comment on whether to include such a requirement and, if so, what conditions or limitations should be associated with it.

c. We further seek comment on whether there should be a specific study process to identify opportunities to enhance the grid for purposes beyond maintaining reliability or reducing current congestion. Such a process would allow interested entities, including state resource agencies, siting bodies and commissions, load-serving entities, or other market participants to request that the transmission provider model grid upgrades needed to accommodate the construction of new resources, *e.g.*, remote coal, nuclear or wind on a local and regional basis and prior to the existence of an actual proposal for such resources. Such a process could provide the information necessary to allow interested entities to proactively evaluate, on a nondiscriminatory basis, different resource options in light of the differing transmission infrastructure needs associated with them. We recognize that resource planning is traditionally performed at the state level and do not believe that any such study process would conflict with these state prerogatives. To the contrary, we believe such a study process could provide states better information to evaluate all relevant resource options in exercising their resource adequacy authority.

d. We also seek comment on whether we should require public utilities to develop cost allocation principles to address the sharing of the costs of new transmission projects. Would the development of specific cost allocation principles provide greater certainty and hence support the construction of new infrastructure? Or is cost allocation better handled on a case-by-case basis? We also seek comment on how, as part of any cost allocation process, to address the fact that upgrades that may not be needed for reliability in the near term (*e.g.*, 3–5 years) may be necessary to support reliability in the longer term (*e.g.*, 10–15 years). Furthermore, because transmission upgrades, particularly multi-state regional backbone facilities, often can require 10 to 15 years to construct, we seek comment on whether the planning process proposed here should be

[206] We note that transmission providers in the Western Interconnection already participate in regional and sub-regional transmission planning processes that include the opportunity for joint financing and ownership of transmission facilities. Such facilities are typically owned by the participants as ''tenants in common'' with each participant owning a pro rata share of the land and common facilities and sharing the costs and expenses in proportion to their ownership percentage in each project. Additionally, all owners participate in the oversight and administration of jointly-owned projects through representation on various administration committees. Among other benefits, this has allowed all participating utilities, large and small, to take advantage of the economies of scale associated with larger transmission projects.

required to look out at least as far as the longest time it would take to build such an upgrade in the region in question.

219. Finally, the Commission seeks comment on the level of detail to be required in transmission providers' OATTs.

C. Transmission Pricing

220. Order No. 888 and the *pro forma* OATT included primarily non-rate terms and conditions of open access non-discriminatory transmission service. The Commission required transmission providers to propose corresponding rates in a subsequent filing under FPA section 205. Similarly, here we do not propose to undertake a comprehensive overhaul of our transmission pricing policies. We do, however, propose a number of reforms to several discrete provisions in the *pro forma* OATT, as further described below. We also provide a clarification of our policy for pricing of system expansions.

1. Imbalances

Energy Imbalances

221. In Order No. 888, the Commission concluded that six ancillary services must be included in an OATT.[207] One of those ancillary services is energy imbalance service under Schedule 4 of the *pro forma* OATT.[208] Energy imbalance service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area.[209] The Commission recognized that the amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer.[210]

222. The Commission found that the energy imbalance service should have an energy deviation band appropriate for load variations and a price for exceeding the deviation band that is appropriate for excessive load variations.[211] The deviation band established by the Commission is an hourly deviation band of ±1.5 percent (with a minimum of 2 MW) for energy imbalance. The Commission explained that this deviation band promotes good scheduling practices by transmission customers, which ensures that the implementation of one scheduled transaction does not overly burden another.[212]

223. With respect to compensation associated with the hourly energy deviation band, the Commission explained that for energy imbalances within the deviation band, the transmission customer may make up the difference within 30 days (or other reasonable period generally accepted in the region) by adjusting its energy deliveries to eliminate the imbalance (*i.e.*, return energy in kind within 30 days).[213] In addition, the Commission explained that the transmission customer must compensate the transmission provider for each imbalance that exceeds the hourly deviation band and for accumulated minor imbalances that are not made-up within 30 days.[214] With respect to the price of energy imbalance service, the Commission explained that it intentionally did not provide detailed pricing requirements.[215] Instead, the Commission required transmission providers to propose rates for energy imbalance service.[216]

224. Although transmission providers have different energy imbalance charges, they typically require customers to correct energy imbalances within the deviation band through return in kind or a financial settlement that requires payment for underdeliveries of energy equal to 100 percent of the transmission provider's system incremental cost for the hour the deviation occurred. For energy overdeliveries, the transmission customer would receive a payment equal to 100 percent of the transmission provider's decremental cost for the hour the deviation occurred.[217] Outside the deviation band, transmission providers either charge the transmission customer: (1) A percentage of the utility's system cost, such as 110 percent of incremental costs for underscheduling or 90 percent of decremental costs for overscheduling, or (2) the greater of a percentage of system costs or a fixed charge, such as $100 per MWh.[218]

Generator Imbalances

225. While the Commission found in Order No. 888 that energy imbalance was an ancillary service, it also recognized that differences arise between energy scheduled for delivery from a generator and the amount of energy actually generated in an hour,[219] commonly called generator imbalance. It concluded, however, that a generator should be able to deliver its scheduled hourly energy with precision and expressed concern that if it were to allow the generator to deviate from its schedule by 1.5 percent without penalty, so long as it returned the energy in kind at another time, it would discourage good generator operating practices.[220] The Commission stated that a generator's interconnection agreement with its transmission provider or control area operator should specify the requirements for the generator to meet its schedule and any consequence for persistent failure to meet its schedule.[221]

226. Subsequently, however, the Commission, in a number of cases, accepted modifications to a transmission provider's OATT to include generator imbalance provisions.[222] Moreover, in Order No. 2003–B, the Commission permitted the transmission provider to include a provision for generator balancing service arrangements in individual interconnection agreements.[223] Further, in a NOPR concerning generator imbalance provisions for intermittent resources, the Commission proposed to establish a standardized schedule under the *pro forma* OATT to address generator imbalances created by

[207] Order No. 888 at 31,703.

[208] *Id.*

[209] *See id.* at 31,960.

[210] Order No. 888–A at 30,230.

[211] *Id.*

[212] *Id.* at 30,232.

[213] *Id.* at 30,229.

[214] *Id.* The Commission further stated that the *pro forma* OATT permits schedule changes up to twenty minutes before the hour at no charge, and that it would allow the transmission provider and the customer to negotiate and file another deviation band more flexible to the customer, if the same deviation band is made available on a not unduly discriminatory basis. *Id.* at 30,232–33.

[215] *Id.* at 30,234.

[216] *Id.*

[217] *See, e.g.*, Arizona Public Service Co., FERC Electric Tariff, Twelfth Revised Volume No. 2, Schedule 4 (Energy Imbalance Charge), accepted in *Arizona Public Service Co.*, Docket No. ER04–442–003 (Sep. 30, 2004) (unpublished letter order); Public Service Company of New Mexico, FERC Electric Tariff, Second Revised Volume No. 4., Schedule 4 (Energy Imbalance Charge), accepted in *Public Service Co. of New Mexico*, Docket No. ER04–416–002 (Sep. 30, 2004) (unpublished letter order).

[218] *See Arizona Electric.*; *see also Idaho Power Co.*, 102 FERC ¶ 61,351 (2003); *see also* Duke Electric Transmission FERC Electric Tariff, Third Revised Volume 4, Original Sheet No. 120 accepted in *Duke Energy Corp.*, Docket No. ER04–812–001 (Jul. 2, 2004) (unpublished letter order).

[219] Order No. 888–A at 30,230.

[220] *Id.*

[221] *Id.*

[222] *See, e.g., Niagara Mohawk Power Corp.*, 86 FERC ¶ 61,009 (1999) (*Niagara Mohawk*); *PacifiCorp*, 95 FERC ¶ 61,145, *order on reh'g and clarification*, 95 FERC ¶ 61,467 (2001); *Alliant Energy Corporate Services, Inc.*, 93 FERC ¶ 61,340 (2000); *Wolverine Power Supply Coop.*, 93 FERC ¶ 61,330 (2000); *Commonwealth Edison Co.*, 93 FERC ¶ 61,021 (2000); *FirstEnergy Operating Cos.*, 93 FERC ¶ 1,200 (2000), *order denying reh'g & granting clarification*, 94 FERC ¶ 61,184 (2001); *Tampa Electric Co.*, 90 FERC ¶ 61,330 (2000), *reh'g denied*, 95 FERC ¶ 61,101 (2001); *Florida Power Corp.*, 89 FERC ¶ 61,263 (1999); *Consumers Energy Co.*, 87 FERC ¶ 61,170 (1999).

[223] Order No. 2003–B at P 74–75.

intermittent resources and to clarify the application of the current energy imbalance provision of the *pro forma* OATT.[224] In particular, the Commission proposed that generator imbalance provisions for intermittent resources would reflect a deviation band of ±10 percent (with a minimum of 2 MW) and allow net hourly intermittent generator imbalances within the deviation band to be settled at the system incremental cost at the time of the imbalance.[225] The Commission also reiterated its policy that a transmission provider may only charge the transmission customer for either hourly generator imbalances or hourly energy imbalances for the same imbalance, but not both.

227. A variety of different deviation bands and pricing methods are on file for generator imbalances. Rates for generator imbalance underdeliveries range from the greater of $100/MWh or 110 percent of system incremental cost to the greater of $150/MWh or 200 percent of the incremental cost.[226] Generator imbalance rates for overdeliveries range from 90 percent[227] of system decremental cost to 50 percent[228] of the decremental cost.

228. In the NOI, we asked several questions about the need to modify the treatment of energy and generator imbalances. For example, with respect to energy imbalances, the Commission asked whether the deviation band of ±1.5 percent continues to be appropriate and whether penalty charges should be eliminated entirely for transmission customers, or whether transmission customers should be charged no more than the control area's cost of supplying energy to correct the imbalance. With respect to generator imbalances, the Commission asked if comparability in the treatment of generator imbalances is needed, how generator imbalances should be priced, and whether a generator imbalance provision should be included as a schedule in the *pro forma* OATT rather than in generator interconnection agreements.[229]

Comments

229. Many commenters assert that the deviation band of 1.5 percent for energy imbalances continues to be appropriate. EEI argues that the deviation band for energy imbalance service is reasonable because it appropriately balances the need to protect transmission system reliability and the need for operational flexibility. LG&E argues that the deviation band of ±1.5 percent and associated penalties for transactions that fall outside this band are an appropriate means of disciplining market participants. Southern argues that allowing a larger deviation band could encourage gaming and leaning on the system, which ultimately would jeopardize reliability. Southern adds that allowing deviations of more than 1.5 percent without penalty could cause, among other things, inefficient use of generation resources and inappropriate cost shifting from those most able to control imbalances to those lacking such control.

230. Several commenters assert that the deviation band for energy imbalances should be modified. APPA argues that imbalances outside the deviation band currently must be paid off at rates that often bear no resemblance to the actual cost that the transmission provider likely incurs to deal with the imbalance. APPA recommends revising Schedule 4 to increase the deviation band and to institute a graduated series of increasing penalties outside of the expanded deadband. Public Power Council states that there is no forecast model that accurately predicts actual fluctuations in loads within the deviation band and therefore penalties will not induce parties to schedule more accurately. Public Power Council states that the 1.5 percent deviation band encourages loads to over-schedule and encourages the Commission to either expand the deviation band or adopt a multi-band system similar to the one Bonneville has in place. Snohomish notes that Bonneville has two deviation bands beyond the 1.5 percent that have greater penalties when customers cannot manage their energy imbalances within the first deviation band and states that this approach seems equitable because it gives customers the proper incentives to keep their schedules accurate.

231. Constellation argues that the Commission should eliminate energy imbalance penalties and require that imbalances be netted across all suppliers and with respect to each customer. EPSA contends that imbalances outside the deviation band should be netted on a system-wide basis and settled at incremental costs. Snohomish states that it prefers an approach that provides for netting and penalizes intentional deviation. Nevada Companies explains that its energy imbalance tariff nets all negative and positive imbalances such that penalties are only invoked if there is a net positive or a net negative imbalance outside of the deviation band. PPL also advocates that the Commission should allow suppliers the flexibility to net and trade imbalances in areas where no imbalance market exists.

232. Duke contends that requiring transmission providers to supply imbalance service at a system incremental cost may eliminate the erroneous perception that the existing charges are discriminatory, but such an approach does nothing to solve the problems that imbalances cause, nor does such an approach reflect the actual costs of leaning on and dumping on the system. A number of commenters argue that penalties should be imposed because without penalties there is insufficient economic incentive for transmission customers to properly schedule and, as such, reliability could be harmed.[230] WAPA states that if a balancing authority has very limited generation capacity (either physical or market) available for the provision of energy imbalance service, the assessment of penalties is warranted in order to establish a disincentive to improper behavior that potentially may affect reliability.

233. Powerex notes that some mechanism should be in place that distinguishes between intentional or repeated deviations and unit outages or *force majeure* events and argues that penalties should be tiered so that they increase exponentially as a generator's imbalances increase.

234. With regard to generator imbalances, EEI, Entergy, MidAmerican, and Southern contend that the Commission should continue its current policy, as established in Order No. 2003, of requiring that generator imbalances be addressed either in the OATT or in the generator interconnection agreement. EEI, MidAmerican and Entergy contend that the Commission

[224] *Imbalance Provisions for Intermittent Resources; Assessing the State of Wind Energy in Wholesale Electricity Markets*, Notice of Proposed Rulemaking, 70 FR 21349 (Apr. 26, 2005), FERC Stats. & Regs. ¶ 32,581 at P 9 (2005) (Imbalance Provisions Proceeding).

[225] The Commission defined incremental cost as "the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and maintenance costs, and purchased and interchange power costs and taxes." *Id.* at P 9 n.17 (citing *Consumers Energy Co.*, 87 FERC ¶ 61,170 at 61,179 (1999).

[226] *See Duke Energy Corp.*, Docket No. ER05–855–000 (Dec. 20, 2005) (unpublished letter order) (accepting Duke Electric Transmission's Large Generator Interconnection Agreement with Power Ventures Group, LLC (Duke Delegated Letter Order)).

[227] *See Entergy Services, Inc.*, 90 FERC ¶ 61,272 (2000) (concerning various generator imbalance agreements).

[228] *See* Duke Delegated Letter Order.

[229] NOI at P 31.

[230] *E.g.*, MidAmerican, NorthWestern, PacifiCorp, PNM–TNMP, Powerex, Progress Energy, Salt River, and Southern.

should retain the flexibility of transmission providers to deal with the issue of generator imbalances on a case-by-case basis, subject to the requirement that they do not engage in unduly discriminatory or preferential treatment with respect to other generators on the system. Calpine contends that requiring transmission providers to treat generator imbalances in the *pro forma* OATT in the same way regardless of the generator, and in all control areas, would provide greater certainty and consistency for generators and help to eliminate the opportunity for transmission providers to engage in discriminatory behavior. Bonneville argues that its three-tiered pricing and penalty approach for energy imbalances also is appropriate for generator imbalances.

235. PNM–TNMP states that the 1.5 percent deviation band for imbalance service continues to be appropriate except for intermittent resources. For those resources, it maintains, imbalance energy costs should not be punitive, but rather should be designed to allow the transmission provider to recover its full costs of providing the generator imbalance service. NRECA urges the Commission not to revise imbalance provisions in a manner that singles out wind generators for preferential treatment. Northwestern, on the other hand, argues that a generator imbalance service schedule should be included in the *pro forma* OATT for intermittent resources and the service should not apply to traditional generators.

236. Commenters argue that the treatment of imbalances should be made comparable with the treatment of inadvertent energy for transmission providers. APPA argues that Schedule 4 raises concerns about discriminatory treatment because Schedule 4 is not applicable to OATT transmission providers, who clear their imbalances through the use of inadvertent interchange, if they operate their own control areas. TDU Systems contend that transmission providers that operate control areas hold a competitive advantage over non-control area operators solely by virtue of the fact that they have access to balancing options, such as inadvertent interchange, that are not available to all market participants, including customers of the transmission providers. TDU Systems argue that this advantage can be decisive when sellers that do not operate control areas try to compete with control area operators for sales to entities concerned about exposure to the penalties imposed under existing imbalance tariff provisions.[231] East Texas Cooperatives argue that control area utilities, moreover, enjoy a double benefit because: (1) They are not subject to penalties themselves, and (2) the control area operator's own generation is used to provide imbalance service to the other transmission customers in the control area. TAPS asserts that comparability requires affording transmission dependent utilities the same return-in-kind treatment control areas use for inadvertent energy. It maintains that, at a minimum, the Commission should eliminate the $100/MWh penalty, except in egregious circumstances and/or the Commission should expand the return-in-kind deviation band substantially.

237. EEI and Entergy, on the other hand, argue that inadvertent energy and energy imbalances are not comparable and should thus be treated differently. EEI states that a NERC-certified control area is responsible for supporting the reliability of its own area as well as supporting the reliability of the interconnected power system grid. EEI explains that the inadvertent energy that a control area experiences reflects the moment-by-moment netting of load, generation and schedules into or out of the control area, and that inadvertent energy reflects the loads, generator output and schedules of all entities within the control area, and not simply the loads and generation of the transmission provider. Entergy explains that control area interchange imbalances may involve the failure of control areas to match their scheduled inflows and outflows due to contingencies occurring even in another control area.[232]

Discussion

238. The existing energy imbalance charges under Schedule 4 of the *pro forma* OATT and the generator imbalance charges described in Order No. 2003 are the subject of significant concern and confusion in the industry. The Commission is concerned about the variety of different methodologies used for determining imbalance charges and whether the level of the charges provides the proper incentive to keep schedules accurate without being excessive. The Commission proposes to modify the current *pro forma* OATT Schedule 4 treatment of energy imbalances and to adopt a separate *pro forma* OATT schedule for the treatment of generator imbalances. More specifically, the Commission seeks to balance the needs of transmission providers to operate their transmission systems in a reliable manner with the needs of transmission customers to have reasonable access to those systems at just and reasonable rates, as well as the needs of a variety of transmission customers with different generator sources.

239. To achieve this, the Commission proposes to create new energy and generator imbalance schedules based on the following three principles: (1) The charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.

240. Bonneville has taken an energy imbalance pricing approach that appears consistent with the three principles outlined above and seems to be working well. Bonneville's imbalance pricing approach is based on a three-tiered deviation band that would appear workable for both energy imbalance service and generator imbalance service. Under this proposal, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) would be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) would be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) would be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances. Intermittent resources are exempt from the third-tier deviation band and would pay the second-tier deviation band charges for all deviations greater than the larger of 1.5 percent or two megawatts.

[231] *Accord* APPA, Constellation, EPSA, Steel Manufacturers Association, and TAPS.

[232] *Accord* Progress Energy, Salt River, and Southern.

241. The Commission seeks comment on whether this approach should be adopted for inclusion in the *pro forma* OATT for energy and generator imbalances. Does this approach provide sufficient incentives to ensure that transmission systems can be operated in a reliable manner and ensure that customers are treated in a just and reasonable manner?

242. We note that the Bonneville provision allows for greater charges when a customer has an ''intentional deviation.'' [233] We seek comment on whether the *pro forma* OATT imbalance provision should provide for penalties for behavior that represents deliberate reliance on the transmission provider's generation resources, as opposed to scheduling errors, with such penalties being subject to prior notice and approval by the Commission and based on the facts and circumstances of the individual transmission provider.

243. If the Commission adopts revised energy and generator imbalance schedules consistent with the principles proposed in this NOPR, that would eliminate the need for a final rule in the Imbalance Provisions Proceeding in Docket No. RM05–10–000 concerning generator imbalance provisions for intermittent resources. As such, the Commission would expect to terminate that docket concurrent with the adoption of revised energy and generator imbalance schedules in this proceeding.

244. With respect to the pricing of energy and generator imbalances, the Commission believes that charges based on incremental costs or multiples of incremental costs will provide the proper incentive to keep schedules accurate without being excessive. In deriving such charges, the Commission proposes that incremental cost be defined to include both energy and commitment [234] costs (to the extent additional commitments are needed). The Commission seeks comment on how such charges should be calculated, as well as how they would be applied to transmission customers. How should additional demand and energy costs, if incurred in responding to imbalances, such as redispatch, commitment, or additional regulation reserves be appropriately reflected in the calculation of imbalance charges and which customers should be charged for such costs? Who should receive any additional revenue from the charges above incremental costs?

245. The Commission proposes to continue to allow inadvertent energy to be treated differently than energy and generator imbalances.[235] The Commission believes that these two types of service are not comparable. Inadvertent energy represents the difference between a control area's net actual interchange and the net scheduled interchange. It is caused by the combined effects of all the generation and loads in the control area and not simply the loads and generation of the transmission provider. Further, management of inadvertent energy is needed to adhere to NERC standards and to ensure reliability. Many of the variables of inadvertent interchange are beyond the control of individual transmission providers. Because of the nature of inadvertent energy and historical practices, transmission providers pay back imbalances in kind, and the Commission has accepted this treatment as just and reasonable. In contrast, allowing customers to pay back all energy and generator imbalances in kind would not provide sufficient incentives for them to minimize imbalances. Some commenters have argued that the return-in-kind approach to inadvertent energy between control areas is discriminatory because OATT customers are required to bear actual charges for their imbalances. As we have described, we believe the two services are different and hence do not believe that the two should have precisely the same treatment. However, we seek comment on whether the current return-in-kind approach to inadvertent energy encourages leaning on the grid in times of shortage, and therefore whether any reforms in this area are appropriate. Would pricing inadvertent energy at incremental cost (or some variant thereof) be an appropriate disincentive? If any reforms in this area are appropriate, should they be pursued under FPA section 215 as part of the review of reliability standards?

246. Furthermore, we propose to add provisions to schedule 4—Energy Imbalance Service and schedule 9—Generator Imbalance Service of the *pro forma* OATT to reflect the Commission's policy that a transmission provider may only charge a transmission customer for either hourly generator imbalances or hourly energy imbalances for the same imbalance, but not both.[236] We also clarify that this policy only applies to a transmission customer that otherwise would be charged for both generator imbalances and energy imbalances for the same imbalance occurring within the same control area.

247. Finally, the Commission seeks comment on whether or not it is appropriate to allow a transmission customer to net energy and generator imbalances for a particular transaction within a single control area to the extent they offset. For example, if a transmission customer schedules 100 MWh over an hour but has a load of 120 MWh, it would face an imbalance of 20 MW. However, if it also dispatches its generation to the same 120 MWh, should there be no net charge? Similarly, what if a transmission customer schedules 100 MWh but has a load of 80 MWh and dispatches its generation to 80 MWh? Does the potential to allow netting for offsetting imbalances contradict the principle of encouraging good scheduling practices? We also seek comment on what would be a reasonable percentage to net without concerns that allowing such netting would lead to reliability concerns from using unscheduled transmission or would cause redispatch costs by the transmission provider.

2. Credits for Network Customers

248. Section 30.9 of the *pro forma* OATT states that a network customer owning existing transmission facilities that are integrated with the transmission provider's transmission system may be eligible to receive cost credits against its transmission service charges if the network customer can demonstrate that its transmission facilities are integrated into the plans or operations of the transmission provider to serve its power and transmission customers. The section also states that new facilities are eligible for credits when the facilities are jointly planned and installed in coordination with the transmission provider. In the NOI, we asked several questions regarding the Commission's

[233] *See* 2006 Transmission and Ancillary Service Rate Schedules, approved in *United States Dep't of Energy—Bonneville Power Administration*, 112 FERC ¶ 62,258 (2005). The Bonneville tariff provides that ''For any hour(s) that an imbalance is determined by [Bonneville] to be an Intentional Deviation: (1) No credit is given when energy taken is less than the scheduled energy, (2) When energy taken exceeds the scheduled energy, the charge is the greater of: (i) 125% of [Bonneville's] highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.'' An ''Intentional Deviation'' is defined as ''a deviation that is persistent during multiple consecutive hours or at specific times of the day,'' a ''pattern of under-delivery or over-use of energy,'' or ''persistent over-generation or under-use during Light Load Hours, particularly when the customer does not respond by adjusting schedules for future days to correct these patterns.'' *Id.* at 46.

[234] ''Capacity commitment'' generally is defined as the generating capacity committed by a utility to provide capability for another utility to attain its reserve level. *See, e.g.*, *Central & South West Services, Inc.*, 48 FERC ¶ 61,197 at 61,731 n.9 (1989).

[235] *See* Order No. 888–A at 30,233.

[236] Imbalance Provisions Proceeding at 32,123 (citing *Niagara Mohawk*, 86 FERC at 61,028).

policy on credits for new facilities, including whether the Commission should reconsider its policy of denying credits for transmission facilities owned by point-to-point customers.

Comments

249. Many commenters argue that the existing credit requirement has the effect of discouraging joint transmission planning.[237] NRECA asserts that making the existence of joint planning a condition of a customer's eligibility for credits or revenue requirement recovery simply provides another excuse for public utility transmission providers to refuse to engage in joint planning.

250. EEI contends that if the transmission provider is required to provide credit against the customer's cost of transmission service, the cost of the customer's jointly planned and integrated transmission facilities should be automatically added to the transmission provider's cost of service. EEI states that the Commission has adopted a similar approach with respect to third party supply of reactive capability. EEI also argues that automatic credit for customer facilities is inappropriate because in instituting open access and requiring transmission providers to offer network service, the Commission made it clear that it did not direct a merging of the parties' transmission systems or the operation of a joint transmission network.[238] EEI argues that the Commission should retain the requirement that customer transmission facilities are eligible for credits from transmission providers other than RTOs and ISOs only if they meet the integration standard.

251. Some commenters argue that the OATT should not be reformed to include credits for transmission facilities built by point-to-point customers.[239] EEI states that the question posed in the NOI appears to contemplate providing credits to a point-to-point customer who constructs new facilities that are jointly planned with the transmission provider regardless of whether those facilities meet the Commission's standards for integration of customer-owned transmission facilities. Instead, EEI argues, the Commission should apply the test from *Consumers Energy Co.*, which provides that a transmission customer should receive credits against its transmission bill when the transmission provider uses facilities owned by that customer to provide service to other transmission customers.[240] Bonneville and PNM–TNMP state that if applied to existing facilities, credits for point-to-point customers could cause major cost shifts. Bonneville argues that these problems would be especially severe in the Northwest, where there are numerous areas of multiple transmission ownership, both in series and in parallel, and where transmission owners purchase large amounts of transmission from each other. Southern states that to effectuate this proposal, the Commission would need to revise its ''higher of'' pricing requirements, otherwise no point-to-point customer would build transmission facilities when it can require the transmission provider to do so and costs are rolled into rate base. Entergy opposes providing credits for transmission facilities owned by point-to-point service customers because those facilities are not used to integrate resources and loads in the same way that facilities owned by network customers are.

252. Other commenters argue that the Commission should modify the *pro forma* OATT to include a provision allowing credits for transmission facilities built by a point-to-point customer.[241] TAPS states the Commission should re-evaluate its bright line denial of credits for transmission facilities owned by point-to-point customers. TAPS contends that the current section 30.9 integration test may be appropriate for long-term (*e.g.*, at least 5 years) point-to-point customers. South Carolina E&G supports modifying the *pro forma* OATT to provide credits for facilities built by point-to-point customers, but asserts that credits should apply only when the customer's facilities are in service. South Carolina E&G states that after the passage of a defined period of inactivity, such as when a customer takes a facility out of service, the credits should be suspended, to reduce the burden on other customers.

Discussion

253. Section 30.9 of the *pro forma* OATT establishes two categories of facilities owned by network customers that are eligible for credits. First, existing transmission facilities ''integrated with the Transmission Provider's Transmission Systems,'' are eligible for credits if the network customer can ''demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers.'' The second category comprises new facilities (*i.e.*, facilities constructed by the network customer after the service commencement date in the OATT), if the facilities ''are jointly planned and installed in coordination with the Transmission Provider.''

254. We agree with the commenters who argue that section 30.9 should be reformed. We agree that the link between credits for new facilities and the requirement for joint planning can act as a disincentive to coordinated planning, which is contrary to the Commission's original objective in adopting the provision. A transmission provider has an incentive to deny coordinated planning if it believes that the cost of any facilities constructed as a result of that process will have to be borne in significant part by its bundled retail customer.

255. Therefore, we propose to sever the link between credits and planning, and treat the two issues separately within the *pro forma* OATT.[242] Eliminating the link is appropriate because the crediting of integrated facilities serves a purpose independent of the planning obligation. Traditionally, the Commission has allowed a transmission provider to allocate the costs of integrated facilities to all users of the integrated system or grid consistent with the view that the entire grid is interconnected and provides generalized benefits to all users.[243] But because integration is a fact-specific matter, the Commission in Order No. 888 decided that credits were appropriately addressed on a case-by-case basis. [244]

256. Regarding the eligibility for credits, as the Commission stressed in Order No. 888, 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

[237] *E.g.*, Arkansas Cities, East Texas Cooperatives, Nevada Companies, NRECA, PNM–TNMP, Suez Energy NA, TAPS, TransAlta, TDU Systems, and Xcel.

[238] For support, EEI cites *Florida Municipal Power Agency* v. *Florida Power & Light Co.*, 74 FERC ¶ 61,006 at 61,009–10 (1996), *order on reh'g*, 96 FERC ¶ 61,130 (2001), *aff'd sub nom. Florida Municipal Power Agency* v. *FERC*, 315 F.3d. 362 (D.C. Cir. 2003).

[239] *E.g.*, Bonneville, EEI, and PNM–TNMP.

[240] EEI cites *Consumers Energy Co.*, 86 FERC ¶ 63,004 at 65,016 (1999), *order on initial decision*, 98 FERC ¶ 61,333 (2002) and *Northeast Texas Electric Cooperative, Inc.*, 111 FERC ¶ 61,189 at P 6 (2005).

[241] *E.g.*, MidAmerican, South Carolina E&G, TAPS, and Williams.

[242] See Part V.B for a discussion of our proposed planning obligations.

[243] *See, e.g., Pacific Gas and Electric Co.*, 106 FERC ¶ 61,144 at P 12, *reh'g denied*, 108 FERC ¶ 61,297 (2004); *Niagara Mohawk Power Corp.*, 42 FERC ¶ 61,143 at 61,531 (1988); *Otter Tail Power Co.*, 12 FERC ¶ 61,169 at 61,420 (1980).

[244] Order No. 888 at 31,742.

to such credit.[245] Rather, a network customer's transmission facilities must provide additional benefits to the transmission grid in terms of capability, delivery options, and reliability, and be relied upon for the coordinated operation of the grid. The integration standard, in brief, requires that to be eligible for credits under *pro forma* OATT section 30.9, the customer ''must demonstrate that its facilities not only are integrated with the transmission provider's system, but also provide additional benefits to the transmission grid in terms of capability and reliability and can be relied on by the transmission provider for the coordinated operation of the grid.'' [246] This policy is premised on the principle that ''just as the transmission provider cannot charge the customer for facilities not used to provide transmission service, the customer cannot get credits for facilities not used by the transmission provider to provide service.'' [247] The Commission continues to believe that, for existing facilities, the integration standard is the appropriate standard for determining whether a network customer's facilities should be eligible for credits. We clarify, however, that for new facilities, the integration standard must be applied comparably,[248] because application of the integration test in a manner that exclusively benefits the transmission provider is unduly discriminatory, and a violation of the FPA.[249] Specifically, we propose that the network customer shall receive credit for transmission facilities added subsequent to the effective date of the Final Rule in this proceeding provided that: (1) Such facilities are integrated into the operations of the transmission provider's facilities, and (2) if the transmission facilities were owned by the transmission provider, would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the *pro forma* OATT.

257. Thus, the Commission proposes revising section 30.9 to eliminate the disincentive to coordinated planning and investment in the transmission grid (*i.e.*, by deleting language that permits transmission providers to refuse crediting for network-customer-owned facilities that are not part of its planning process) and provide for non-discriminatory crediting for integrated facilities comparable to those transmission provider facilities that are included in rates. We are proposing this change to ensure that section 30.9 does not impede coordinated planning and to otherwise ensure that our crediting policy is just, reasonable and not unduly discriminatory. Our action is not in any way intended to lessen our commitment to coordinated planning between a transmission provider and its customers. To the contrary, we propose elsewhere in the NOPR to require coordinated planning by all transmission providers. This requirement is not linked to the issue of crediting for customer-owned facilities, but rather is a general requirement intended to avoid opportunities for undue discrimination in transmission planning.

258. We decline to allow transmission providers as part of this proceeding to automatically add costs of credits associated with integrated transmission facilities to the transmission provider's cost of service. These costs typically are considered and evaluated as part of a regular cost of service review process. Nevertheless, a transmission provider that wishes to add an automatic adjustment clause to its rates may seek Commission approval for its methodology in a filing submitted under section 205 of the FPA.[250]

259. Finally, the Commission does not propose revising the *pro forma* OATT to expressly allow transmission credits for facilities owned by point-to-point customers. Unlike a network customer, a point-to-point customer only pays for a discrete transmission service over the contract term. The network customer takes a usage-based service which integrates its resources and loads and pays on the basis of its total load on an ongoing basis. The transmission provider includes the network customer's resources and loads in its long-term planning horizon and the two parties coordinate operations of their facilities through a network operating agreement. In this way, network service is comparable to the service that the transmission provider uses to serve its own retail native load, and credits for certain integrated network facilities are appropriate. The point-to-point customer, however, does not purchase integration service, nor does it sign a network operating agreement with the transmission provider. Thus, because of the inherent differences between point-to-point and network service, we do not propose adding a new OATT requirement that the transmission provider make credits generically available to point-to-point customers that own transmission facilities. Nevertheless, there may be some facilities owned by a point-to-point customer that meet all the criteria for credits. Although the Commission is not including a specific provision in the OATT that provides credits for these facilities, consistent with the Commission's statement in Order No. 888, the Commission will address such situations on a fact-specific, case-by-case basis.[251]

3. Capacity Reassignment

260. In Order No. 888, the Commission concluded that a public utility's tariff must explicitly permit the voluntary reassignment of all or part of a holder's firm point-to-point capacity rights to any eligible customer.[252] As for the rate for capacity reassignment, the Commission concluded that it could not permit reassignments at market-based rates because it was unable to determine that the market for reassigned capacity was sufficiently competitive so that assignors would not be able to exert market power. Instead, the Commission capped the rate at 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

[245] Order No. 888 at 31,742–43.

[246] *Southwest Power Pool, Inc.*, 108 FERC ¶ 61,078 at P 17 (2004) (citing Order No. 888–A at 30,271), *reh'g denied*, 114 FERC ¶ 61,028 (2006).

[247] *Id.* at P 20 (citing Order No. 888–A at 30,271 & n.277); *accord East Texas Coop., Inc.* v. *Central & South West Services, Inc.*, 108 FERC ¶ 61,079 at P 28 (2004), *reh'g denied*, 114 FERC ¶ 61,027 (2006); *Southern California Edison Co.*, 108 FERC ¶ 61,085 at P 10 (2004); *Northern States Power Co.*, 87 FERC ¶ 61,121 at 61,488 (1999); *Florida Municipal Power Agency* v. *Florida Power & Light Co.*, 74 FERC ¶ 61,006 at 61,010 (1996), *reh'g denied*, 96 FERC ¶ 61,130 at 61,544–45 (2001), *aff'd sub nom. Florida Municipal Power Agency* v. *FERC*, 315 F.3d 362 (D.C. Cir. 2003).

[248] In Order No. 888, the Commission addressed the comparability requirement:

> We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

Order No. 888 at 31,743 n.452.

[249] Credits may not be necessary if the transmission provider and a transmission customer jointly own the transmission facilities and operate those facilities under the terms of a joint ownership agreement. *See Northern States Power Co.*, 83 FERC ¶ 61,098 at 61,472 (explaining that the crediting provision in *pro forma* OATT section 30.9 was not intended to apply to jointly owned transmission facilities), *order on clarification*, 83 FERC ¶ 61,338, *order denying reh'g and clarification*, 84 FERC ¶ 61,122 (1998), *remanded on other grounds sub nom. Northern States Power Co.* v. *FERC*, 176 F.3d 1090 (8th Cir. 1999).

[250] *See, e.g.*, *id.* at 61,467.

[251] Order No. 888 at 31,742; Order No. 888–A at 30,271.

[252] Order No. 888 at 31,696; *pro forma* OATT section 23.1.

capped at the cost of expansion (price cap).[253]

261. The Commission explained in Order No. 888 that opportunity cost pricing had been permitted at ''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).'' [254] In Order No. 888–A, the Commission explained that opportunity costs for capacity reassigned by a customer should be measured in a manner analogous to that used to measure the transmission provider's opportunity cost.[255] As a result, the Commission required that assignors proposing to recover opportunity costs file with the Commission a fully developed formula describing the derivation of opportunity costs. The Commission further required that all information necessary to calculate and verify opportunity costs must be made available to the eligible customer.[256]

262. In the NOI, the Commission asked whether the price cap remained reasonable, or whether it should be modified or eliminated to further encourage capacity reassignment.

Comments

263. Some commenters argue that the price cap should not be eliminated.[257] According to EEI, transmission pricing policies do not have much impact on reassignment of capacity rights, so changes to the approach would be largely irrelevant.

264. Southern contends that elimination of the price cap might result in inefficiencies by providing an incentive for entities to hoard transmission capacity. Moreover, Tacoma and Public Power Council reason that because transmission remains a monopoly business, cost-based rates remain appropriate.

265. Snohomish expresses concern that eliminating the price cap may encourage speculation in the purchase of transmission capacity, greatly driving up costs for transmission customers. Snohomish, nonetheless, states that auctions of secondary capacity may be appropriate, provided the capacity is purchased under a long-term contract for the purpose of serving load and the sale does not reduce transmission capacity for existing customers that have contracted for the capacity.

[253] Order No. 888 at 31,697.

[254] *Id.* at 31,740.

[255] Order No. 888–A at 30,224.

[256] *See id.;* Order No. 888 at 31,740.

[257] *E.g.,* Ameren, EEI, Southern, and Tacoma Power.

266. Other commenters argue that the price cap should be revised.[258] Exelon supports the maximum flexibility possible in use of the transmission system, including allowing transmission rights to be assigned and redirected—so long as the transfer capability is available and existing service will not be curtailed. Exelon recommends that the Commission modify the OATT to permit transmission customers to charge market-based rates for transmission capacity in the secondary market. This change, Exelon argues, would provide greater incentive for the owner of the transmission right to actively pursue reassigning the transmission service, thereby using the transfer capability more efficiently. Alcoa states that economic incentives are needed to enable a secondary transmission capacity market to develop and thrive.

267. EPSA and Constellation argue that the only desirable modification to this pricing policy would be to eliminate the requirement that transmission customers file with the Commission a method to impose opportunity cost pricing. EPSA states that to its knowledge, no transmission customer has yet been able to develop and file a predefined formula mechanism that would serve as an opportunity cost rate, probably because opportunity cost pricing reflects dynamic market conditions. MidAmerican claims that even when there is no disagreement over the assignor's determination of opportunity costs, considerable time may be required to prepare and obtain approval from the Commission of the resulting FPA section 205 filing. EPSA asserts that the market itself will cap the value of reassignment at the price the transmission provider would charge, *i.e.*, its expansion cost. Constellation states that prices of reassigned capacity will be disciplined by the opportunity costs of releasing the capacity. Both Constellation and EPSA state that the Commission should recognize that opportunity costs for released transmission capacity are dynamic and provide a market discipline on the price that any seller will charge and any purchaser will pay for reassigned capacity. In response to EPSA's proposal to eliminate the requirement that transmission customers file with the Commission a method to impose opportunity cost pricing, APPA argues that to ensure that the price a seller would charge for firm transmission capacity is just and reasonable, as the FPA requires, the Commission should require such a filing.

[258] *E.g.,* Alcoa, Constellation, EPSA, Exelon, and MidAmerican.

268. While Cinergy maintains that the current pricing approach for capacity assignments is appropriate, it supports consideration of new alternatives that would allow more effective capacity reassignment by the transmission customer. Cinergy asserts that one area that could be considered is to require the transmission provider to provide more clarity on how reassignment requests are analyzed for approval and the options available to the transmission customer to post existing service for reassignment.

269. Williams and Powerex argue that revising the price cap will not encourage greater capacity reassignment. Williams submits that other non-price limitations on capacity reassignment—such as the requirement that the assignee utilize the same source and sink as the original customer—are the real reasons there has not been more capacity reassignment. Stated differently, Williams contends that the price cap does not restrict capacity reassignment—source and sink requirements do.

Discussion

270. In Order No. 888, the Commission explained that it expected capacity reassignment to achieve three goals: ''(1) help [customers] 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.'' [259] Because capacity reassignment does not appear to have developed into a competitive alternative to primary capacity, the Commission is proposing modifications to its existing pricing policy. We propose removing the price cap on capacity reassignment and allowing negotiated rates for transmission capacity reassigned by transmission customers. We do not propose to lift the price cap for capacity resold by transmission providers or their affiliates due to market power concerns.

271. The Commission notes that transmission customers have not used the opportunity cost pricing option for capacity reassignment. Comments suggest that this may be due in part to the complexity of establishing an opportunity cost formula, or the administrative hurdle of filing and supporting a proposal. Simply put, the goals of the capacity assignment program remain important to the

[259] Order No. 888 at 31,696.

Commission, but the price cap has not served as a useful means of achieving them. While we recognize that other factors may inhibit capacity reassignment, eliminating the price cap should provide more flexibility to market participants and encourage customers to sell their capacity to another customer who values the capacity more highly. It also will facilitate the release of capacity and encourage the maximum number of voluntary transactions to occur in a secondary market, which will benefit all market participants consistent with the Commission's goals for capacity reassignment.

272. Although in Order No. 888 the Commission decided not to allow reassignment at market-based rates because of concerns that capacity assignors might exert market power, due to several factors, we now believe that market forces will limit the ability of most assignors to exert market power. First, we expect that competition among releasing customers will restrict the potential exercise of market power. Second, the Commission will monitor the market by requiring quarterly reports and regular OASIS postings from transmission providers based on information submitted to them from reassigning customers regarding their reassignment activity (including the negotiated rate). The Commission's complaint procedures and the Enforcement Hotline also are available for participants raising market power concerns, which should supplement the Commission's existing market oversight efforts. Third, the continued regulation of rates for primary capacity will act as a check to ensure just and reasonable reassignment rates. For example, without congestion on the transmission system, the transmission provider's rate on file serves as the de facto price cap and, if congestion exists, the ''incremental rate,'' which reflects the transmission provider's cost of expansion, should act as a price ceiling for long-term transactions.

273. The Commission concludes that because the price cap appears to have reduced customers' transmission options, removal of the price cap is warranted without a market-by-market analysis. Our reform is intended to provide alternatives for customers that value the capacity more highly. The Commission finds that lifting the price cap strikes a reasonable balance between promoting more efficiency through trading and relying upon competition and price disclosure to prevent anticompetitive behavior. Though we recognize that the price of reassigned capacity may temporarily exceed the cost of expansion, that price signal is an important economic incentive to induce greater transmission investment.

274. Concerns have been raised that allowing negotiated rates may provide an incentive to ''hoard'' capacity, or to reserve transfer capability for no legitimate use other than to speculate on the price of the reassigned capacity. The ability of a transmission customer to hoard capacity is not without limits in that the transmission provider has the obligation to resell as non-firm point-to-point service any firm point-to-point transfer capability reserved by a customer but not scheduled within the time-frames established in *pro forma* OATT section 13.8. As discussed above, we believe that the incentive for the transmission customer to hoard would be limited by the transmission provider's cost of expansion for long-term transactions. Thus, we believe that the greater efficiency created by a more effective capacity trading market for customers who need capacity during peak periods outweighs such concerns and that hoarding concerns are overstated. However, we seek comment on whether circumstances exist where unaffiliated transmission customers could amass market power similar to that of the transmission provider.

275. We do not propose lifting the price cap for all assignors. A stated goal of capacity reassignment is to ''reduce the market power of transmission providers by enabling customers to compete.'' [260] Commission precedent has allowed transmission provider affiliates to reassign capacity under the price cap,[261] and we propose to continue this policy. To allow transmission providers and their affiliates to use negotiated rates allows the transmission provider to use its primary market power in the secondary market. A transmission provider not subject to a price cap would have the ability and incentive to exercise market power to favor its own generation sales when it operates and administers the reassignment process. Furthermore, lifting the cap for the transmission provider may eliminate the incentive to build or expand, as it may allow the transmission provider to take advantage of congested pathways to charge rates above the cost of expansion. Because these expected outcomes would reduce the ability of other customers to compete, and undermine the development of a viable secondary market, we conclude that it remains appropriate to require transmission providers and their affiliates to conform to the price cap for capacity reassignment.

276. The Commission seeks comment on the quarterly reports and OASIS postings we propose to require from transmission providers under this proposal. They will be based on information that we will require assignors to give to transmission providers. What information should we require in the quarterly reports and OASIS postings, *i.e.*, information about the capacity released, the original rate paid for that capacity, the price charged to the assignee for the capacity, and the term of the assignment? Is other information necessary for operational and reliability purposes? Are additional reports by assignors to the transmission provider necessary, and if so, what information should be reported by assignors? Should the Commission establish a new quarterly reporting process, *e.g.*, a new form, or utilize the existing electronic electric quarterly report procedures? How frequently should the OASIS postings be made?

4. ''Operational'' Penalties

a. Unauthorized Use Penalties

277. Section 13.7 of the *pro forma* OATT stipulates that a point-to-point service customer's use of the transmission system may not exceed the firm capacity it has reserved at each point of receipt and each point of delivery except as specified in section 22 of the *pro forma* OATT.[262] Section 13.7 of the *pro forma* OATT also directs the transmission provider to specify the rate treatment and all related terms and conditions for an unauthorized use operational penalty in the event that a point-to-point customer exceeds its firm reserved capacity at any point of receipt or point of delivery. Section 14.5 of the *pro forma* OATT contains similar provisions for an unauthorized use penalty in the event that a transmission customer exceeds its non-firm point-to-point service capacity reservation. The *pro forma* OATT does not otherwise address unauthorized use penalties.

278. In *Allegheny Power,* the Commission capped unauthorized use penalties at a level equal to twice the standard rate for the service at issue.[263] In addition, the Commission clarified that the standard rate to be used as the

[260] *Id.*

[261] *Commonwealth Edison Co.*, 78 FERC ¶ 61,312 at 62,336 (1997).

[262] Section 22 (Changes in Service Specifications) of the *pro forma* OATT prescribes the circumstances under which the transmission customer may modify the point of delivery and the point of receipt for an existing firm point-to-point service reservation.

[263] *Allegheny Power System, Inc.*, 80 FERC ¶ 61,143 at 61,545–46 (1997) (*Allegheny Power*).

basis of the unauthorized use penalty charge must be that of the service at issue, without regard to the duration of the violation; *i.e.*, if overuse occurs for one hour, but the service overused is weekly service, the penalty charge is to be capped at twice the standard weekly rate.[264] In *APS,* the Commission issued an audit report to Arizona Public Service Company (APS) that contains two findings that Commission audit staff characterized as unauthorized use of transmission service.[265] In the first finding, APS's wholesale merchant function did not request and pay for point-to-point service to support some of the off-system power sales it made at trading hubs where APS system resources were directly connected. In the second finding, APS incorrectly treated the Phoenix Valley 230kV system as a single node on its transmission system. As a result, off-system sales made by generators connected to the Phoenix Valley system should have been, but were not, supported by point-to-point service. Other than these cases, the Commission has not addressed the appropriate method of applying unauthorized use penalties pursuant to the provisions of sections 13.7 and 14.5 of the *pro forma* OATT.

Comments

279. MidAmerican states that unauthorized use penalties should only be imposed if the *pro forma* OATT clearly specifies that they are applicable to a proscribed conduct.

Discussion

280. We propose to clarify the circumstances under which we would expect transmission providers to assess unauthorized use penalties. This clarification will eliminate a potential source of discretion in the implementation of the *pro forma* OATT and will assist the Commission in its enforcement of the obligations imposed by it. Specifically, we propose to clarify that unauthorized use penalties apply to any circumstance when a transmission customer uses transmission service that it has not reserved.[266] An unauthorized use penalty would be assessed in circumstances when a transmission customer has a transmission service reservation, but uses transmission service in excess of its reserved capacity. An unauthorized use penalty also would be assessed if a transmission customer uses transmission service when it does not have a transmission service reservation, including the situations described in *APS.* We further clarify that an unauthorized use penalty would not be assessed in circumstances when a transmission customer inappropriately uses a network service reservation to support an off-system sale, as discussed in Part V.D.7. However, a transmission customer that inappropriately uses network service would be required to pay for the point-to-point service it should have reserved and could be subject to a civil penalty depending on the circumstances. We seek comment on whether the current policy that limits unauthorized use penalties to twice the standard rate for the service at issue has resulted in penalties that are not just and reasonable; and, if so, we seek comment regarding provisions that would yield unauthorized use penalties that are just and reasonable.

b. How Transmission Providers Should Pay Operational Penalties

Comments

281. In the NOI, the Commission observed that the existing *pro forma* OATT allows transmission providers to impose certain operational penalties against transmission customers for violations of the *pro forma* OATT, but does not address the adverse consequences to a transmission provider who violates its OATT.

282. Several commenters indicate that a transmission provider would not face the same financial consequence as other transmission customers when the transmission provider or an affiliated transmission customer pays an operational penalty. TAPS notes that applying customer-focused penalties to the transmission provider is meaningless if a transmission provider merely pays itself. EPSA suggests that the Commission include provisions in the new *pro forma* OATT to ensure that the penalty imposes a true financial consequence, *e.g.*, penalties imposed on a transmission provider should be distributed to those OATT customers that were taking service during the period in which the violation occurred. ELCON suggests that the *pro forma* OATT be revised to provide for tariff-based sanctions against a transmission provider that fails to comply with its OATT. Occidental argues that one of the fundamental problems with the current OATT is the lack of tariff-based penalties for violations. Occidental states that tariff-based penalties are needed to focus transmission providers on compliance and to permit customers and the Commission's enforcement staff to bring both specific tariff violations and general issues of non-compliance before the Commission.

Discussion

283. We propose to have transmission providers pay non-offending, unaffiliated transmission customers when the transmission provider or its affiliate incurs operational penalties. This proposal is consistent with our prior findings that operational penalties collected by the transmission provider should be credited back to non-offending transmission customers in order to provide an incentive to the transmission provider to develop non-penalty remedies that will elicit appropriate behavior by transmission customers.[267] For those transmission providers subject to operational penalties, we propose to require the transmission provider to make an annual compliance filing to notify the Commission of the amounts of all such operational penalties incurred during the year and to propose a method to identify non-offending, unaffiliated transmission customers to which the transmission provider would distribute penalty amounts. In addition, we propose to allow a transmission provider to avoid an annual compliance filing by making a one-time filing to propose a mechanism through which it would identify non-offending, unaffiliated transmission customers and a method by which it would distribute the operational penalties it or its affiliates have incurred to the identified transmission customers. We also propose to prohibit transmission providers from recovering for ratemaking purposes or through any service or facility under the Commission's jurisdiction any cost it incurs when it or an affiliate pays an operational penalty.

5. ''Higher of'' Pricing Policy

284. In Order No. 888, the Commission stated that system expansions should be priced at the higher of the embedded cost rate (including the expansion costs) or the incremental cost rate, consistent with the Transmission Pricing Policy

[264] *Id.* at 61,546 n.131.

[265] *Arizona Public Service Co.,* 109 FERC ¶ 61,271 at P 6 (2004) (*APS*).

[266] The revised *pro forma* OATT reflects this proposed reform in sections 13.7 and 30.4.

[267] *See, e.g., Carolina Power & Light Co.,* 103 FERC ¶ 61,209 (2003); *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services,* Order No. 637, 65 FR 10156 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,091 at 31,315 (2000) (noting that ''to the extent that penalty revenues are generated, the required crediting of penalty revenues will eliminate any economic incentive for pipelines to rely on penalties rather than inducements''); *order on reh'g,* Order No. 637–A, 65 FR 35705 (Jun. 5, 2000), FERC Stats. & Regs. ¶ 31,099 (2000).

Statement.[268] The Commission has explained that when rolling in the costs of network upgrades incurred to meet a transmission service request would have the effect of raising the average embedded cost rate paid by existing customers, the transmission provider may elect to charge an incremental cost rate for the new service and thereby insulate existing customers from the costs of any necessary system upgrades. However, the transmission provider may not charge both an incremental cost rate and an embedded cost rate associated with existing network transmission facilities.[269]

285. Although we are not undertaking generic transmission pricing reform in this proceeding, we are concerned that our existing policies may not be being applied consistently and, as a result, customers may be quoted prices that are not consistent with the ''higher of'' policy. We understand that customers typically are quoted an incremental rate in the form of a total dollar amount of needed facility upgrades (*e.g.*, $5,000,000) rather than in the form of a monthly transmission rate that can be compared, on an ''apples-to-apples'' basis, to the embedded cost rate. Presenting an incremental rate as a lump sum payment request is inconsistent with our ratemaking policy and has the potential to discourage customers from proceeding with service requests.[270] As we have noted, under our ''higher of'' pricing policy for network upgrades, the transmission provider should compare the monthly revenue requirement from the upgrade to the monthly revenue requirement from the embedded transmission rate.[271] We also have said that the incremental rate should be established by amortizing the cost of the upgrades over the life of the contract.[272] Presenting the incremental charge in the form of a monthly rate allows a customer seeking a lower rate to choose to request a longer transaction term.

286. We encourage comments on whether changes to the *pro forma* OATT are necessary to ensure that incremental costs are presented as monthly rates for service.

D. Non-Rate Terms and Conditions

287. In this section, we propose a number of reforms to non-rate terms and conditions of service under the *pro forma* OATT. We propose these reforms to eliminate opportunities for undue discrimination, to ensure that the services offered under the *pro forma* OATT are just and reasonable, to increase the transparency of service being provided, and to provide clarity with respect to terms and conditions that have caused confusion in the industry.

1. Potential Modifications to Long-Term Firm Point-to-Point Service

288. In Order No. 888, the Commission required all public utilities to offer both firm and non-firm point-to-point service and firm network service on a non-discriminatory open access basis.[273] In the NOI, the Commission asked for comments on pricing policies that can create an incentive to maximize the use of the transmission system.[274] Also, the Commission asked whether the OATT should require transmission providers to offer new transmission services, such as conditional firm, partial firm, and seasonal firm service.[275] Further, the Commission asked in the NOI whether deviations from the ''higher of'' pricing policy would encourage greater incremental pricing of redispatch service.[276]

Comments

289. Some commenters support the inclusion of a required new service and contend that the existing rules for long-term firm point-to-point service pose barriers to new entry. Constellation states that new products are needed that facilitate the efficient use of the transmission system in a competitive market. AWEA and EPSA argue that a long-term request for service from a new generator can be denied because there are reliability violations in only a few hours of a year, even though firm service is nonetheless available for the large majority of hours of the year. They also argue the existing grid is underutilized and that these practices only exacerbate this problem. EPSA further states that some transmission provider base case models show that the transmission provider is operating its system to serve its bundled retail native load under contingencies that the transmission provider would not accommodate for an OATT customer.

290. PPL argues that the Commission should enforce the requirement in section 13.5 of the *pro forma* OATT that transmission providers must redispatch to relieve congestion that may only occur during a few hours a year. PPL further contends that transmission providers have the incentive to simply deny requests for transmission over a path that experiences occasional congestion, rather than properly undertake redispatch actions to minimize this congestion. Others state that they have not received an offer by a transmission provider to redispatch to accommodate a request for transmission service, but instead are given no choice but to pay for facilities studies that are costly and time consuming.[277] Entergy states in its reply comments that it only evaluates redispatch as part of a system impact study if requested by the transmission customer.

291. Several commenters suggest that pricing complexities and certainty of recovery must be resolved before requiring mandatory redispatch. These commenters state that the cost of redispatch is more than the fuel cost differential and includes hard to quantify costs such as start-up costs, higher capital costs due to shorter life and accelerated replacement, higher maintenance costs, and potential emergency power purchases to serve load in constrained areas.[278]

292. PacifiCorp suggests that the higher charge, whether embedded costs or redispatch costs, be determined on a monthly basis rather than making a one-time determination prior to commencement of service. PacifiCorp argues that the typical cost analysis fails to consider the complexity of determining redispatch. PacifiCorp contends that cost estimates become increasingly unreliable as the analysis

[268] *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act,* Policy Statement, 59 FR 55031 at 55037 (Nov. 3, 1994), FERC Statutes and Regulations ¶ 31,005 at 31,146 (1994), *order on reconsideration,* 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

[269] *See* Northeast Utilities Service Company (Re: Public Service Company of New Hampshire), Opinion No. 364–A, 58 FERC ¶ 61,070 (1992), *reh'g denied,* Opinion No. 364–B, 59 FERC ¶ 61,042, order granting motion to vacate and dismissing request for rehearing, 59 FERC ¶ 61,089, *aff'd in part and remanded in part sub nom.* Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993), order on remand, 66 FERC ¶ 61,332, *reh'g denied,* 68 FERC ¶ 61,041 (1994) *pet. denied; Pennsylvania Electric Co.,* 58 FERC ¶ 61,278, *reh'g denied,* 60 FERC ¶ 61,034 (clarifying pricing policy), *reh'g denied,* 60 FERC ¶ 61,244 (1992), *aff'd sub nom. Pennsylvania Electric Co.* v. *FERC,* 11 F.3d 207 (D.C. Cir. 1993).

[270] *Southwest Power Pool, Inc.,* 100 FERC ¶ 61,096 (2002) (designing a rate to include a balloon payment is not a substitute for a properly designed rate).

[271] *Southwest Power Pool, Inc.,* 112 FERC ¶ 61,319 at P 33 (2005).

[272] *Southwest Power Pool, Inc.,* 98 FERC ¶ 61,256 (''We agree with SPP that the amortization period for upgrade costs should match the contract period. * * * As the customer is only obligated to take service for the term of the contract, it is reasonable that the costs only be amortized over the term of the contract.''); *reh'g denied in pertinent part,* 100 FERC ¶ 61,096 (2002).

[273] Order No. 888 at 31,690.

[274] NOI at P 13.

[275] *Id.* at P 13.

[276] *Id.* at P 12.

[277] *E.g.,* AWEA, Arkansas Cities, EPSA, and Renewable Energy.

[278] *E.g.,* Ameren, EEI, Progress Energy, and Southern.

extends over time, and the complications of one-year transmission service agreements with rollover options make an accurate calculation nearly impossible.

293. AWEA provides a detailed proposal for conditional firm service, in which the transmission provider would identify certain months, weeks, or days when firm transmission service may be limited or unavailable and identify the number of potential hours during those conditional times, when the customer could have its reservations cut or reduced prior to any firm customer reductions. Under specified conditions, for a limited number of hours over a set number of ''conditional'' months, weeks, days or hours, the firm service may be reduced day-ahead by the transmission provider, with conditional firm service provided instead in those hours firm service is unavailable. The ''conditional'' periods would be established when the service is offered. Also, capacity commitments for conditional firm service would be accounted for in ATC calculations prior to new sales of short-term firm transmission service. Commenters support a requirement that transmission providers post on OASIS the paths for which conditional firm service is available, clearly listing the available capacity for each period, and hours during which firm service is available or curtailment is possible as a result of congestion.[279]

294. Those supporting conditional firm service argue that it should be offered to customers requesting long-term firm service when firm ATC is not available during all hours of the request, and allow the transmission customer to obtain service when it would otherwise be denied.[280] As for the rate design of the service, EPSA and PPL recommend that it include either a discount from the firm rate to reflect the reduction in use at the system peak or no discount from the firm rate, but customers taking conditional firm service would have a right of first refusal when firm service becomes available for the hours in which they have agreed to be curtailed.

295. Commenters arguing against a requirement to provide conditional firm service argue that it would degrade the quality of service received by existing long-term firm point-to-point and network customers.[281] Also, Bonneville argues that providing conditional firm service would require modification to the current curtailment priorities in the OATT and the design and purchase of systems to track the purchases and implement the more complex curtailment schemes. TAPS notes that PacifiCorp amended its OATT to make more explicit the potential for granting part of a request for firm service in terms of both the amounts of service and/or the periods of time for which there is sufficient ATC.[282] If the Commission develops new services, TAPS contends that the Commission should build on PacifiCorp's OATT amendments. Many commenters that object to requiring new transmission services recommend that the Commission encourage transmission providers to develop and adopt new services in response to customer needs.[283] Ameren explains that this process should result in additional services being provided that meet the needs of the customers, that are physically feasible considering the existing uses of the system, and that do not adversely affect the service provided to other users of the system and are not unduly discriminatory. Finally, several commenters express a general sentiment against requiring a service that may not be suited to all regions or systems.[284]

296. Commenters also expressed support for services aside from, or in addition to, conditional firm service. Exelon proposes that the Commission should require ''seasonal firm'' service, though other commenters ask if seasonal firm service would invite hoarding or ''cream skimming.'' MidAmerican contends that in most cases, the need for seasonal service can be accommodated by multiple consecutive purchases of monthly service. PPL supports a required ''partial firm'' service that is confirmed and available on a firm basis but provided in various amounts over an annual period. PPL states that the amount of partial firm service offered would be shaped to match the available capacity within each interval or the year. Powerex and WAPA argue long-term priority non-firm point-to-point service is the most workable new service.

297. MidAmerican states that various transmission providers interpret and apply the provisions of section 19.7 (Partial Interim Service) of the *pro forma* OATT in different ways. MidAmerican states that the Commission should clarify whether section 19.7 refers to a partial period of service (*i.e.*, granting firm service for the full MW amount of the initial request, but for only a portion of the requested time period), or a partial quantity of service (*i.e.*, granting firm service for the time period of the initial request, but for only a portion of the requested full MW amount). MidAmerican suggests that the revised OATT should provide that partial interim service be offered both for partial periods and for partial quantities.

298. Bonneville states that, currently, when a customer accepts an offer of partial service, Bonneville keeps the remaining portion of the customer's request in the queue if the customer executes a system impact study agreement. Bonneville contends that the Commission's OASIS Standards and Communication Protocols, however, appear to disallow this result, as does standard OASIS functionality. Bonneville asks that the Commission clarify whether the Commission intends that a customer accepting an offer of partial service should lose its position in the queue.

299. EPSA further argues that transmission providers should be required to accommodate a request for any service, whether or not articulated in the new OATT, to the extent they can do so, on a nondiscriminatory basis and without unreasonably affecting reliability. EPSA also states that the burden should be on the transmission provider to state in writing why it cannot accommodate any given request.

Discussion

Proposed Findings

300. The Commission preliminarily finds that the existing methods for evaluating requests for long-term firm point-to-point service may no longer be just, reasonable and not unduly discriminatory. We believe that transmission providers may evaluate transmission availability to serve long-term transmission service requests in a manner that is not comparable with the method they use to evaluate transmission needs for bundled retail native load and, therefore, that certain reforms are necessary to ensure comparability.

301. When a transmission provider considers new resources to serve its bundled retail native load, the

[279] *E.g.,* EPSA and PPL.

[280] *E.g.*, AWEA, Constellation, EPSA, MidAmerican, PPL, and Renewable Energy.

[281] *E.g.*, APPA Reply Comments, Powerex, and Salt River.

[282] *See* PacifiCorp Open Access Transmission Tariff, section 19.7, FERC Electric Tariff, Fifth Revised Volume No. 11, Substitute Original Sheet No. 100 (effective April 26, 2004); *see also* PacifiCorp Open Access Transmission Tariff, Schedule 7, Long-Term Firm Point-To-Point Transmission Service, section 2, FERC Electric Tariff, Fifth Revised Volume No. 11, First Revised Sheet No. 252 (effective April 1, 2006) (rates for partial delivery of long-term firm point-to-point transmission service).

[283] *E.g.*, Ameren, Bonneville, Cinergy, EEI, KCP&L, Nevada Companies, NRECA, Salt River, Sempra Global, Southern, TVA, and WAPA.

[284] *E.g.*, Ameren, Cinergy, Salt River, and Southern.

transmission provider will not eliminate an otherwise economic option because the resource may not be deliverable in a few hours of the year. Rather, the transmission provider will evaluate whether it can redispatch its resources as necessary to ensure that load is served on a reliable and economic basis. If redispatch is needed in only a few hours of the year, the transmission provider typically will not construct new facilities to accommodate new resources. Rather, the transmission provider will look for a resource at a different location to fulfill its needs on a least cost basis taking into account transmission and energy costs. This use of redispatch to accommodate a new resource means that the resulting service is provided even though the transmission provider's power flow studies show that ATC is not available in all hours of the year. In this situation, the new resource receives a firm service that is not currently available on many systems to OATT customers because the transmission provider uses redispatch on a long-term basis to accommodate a new resource for which ATC is not available in every hour; in some respects, this firm service is similar to conditional firm service because it uses firm transmission capacity to serve bundled retail native load even though the resource is not deliverable in every hour of the year.

302. The Commission believes that the current practices for evaluating long-term transmission service requests generally may not reflect the same practices used to evaluate transmission needs to serve bundled retail native load. Under current practices, the transmission provider evaluates whether service can be granted in every hour of the year that is modeled and, if not, it informs the customer that long-term firm transmission service cannot be provided out of existing transmission capacity. Section 19.3 of the *pro forma* OATT provides that a system impact study is required before the transmission provider must identify available redispatch options. Before redispatch options are offered, however, the customer must also agree to fund a facilities study to determine whether redispatch is less expensive than the transmission facilities upgrades.[285] Thus, it is only if the customer requests a system impact study and facilities study, and agrees to pay for the studies, that the request will be evaluated further and the option of redispatch will be offered to the customer. This study process is both time consuming and expensive. More importantly, it differs from the evaluation typically undertaken by the transmission provider in deciding whether transmission is available to serve bundled retail native load with a new resource.

303. In Order No. 888, the Commission's goal was to ''facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa.'' [286] The first part of this goal, development of competitive supplies, has been realized to some degree.[287] However, the lack of transmission access threatens the viability of customer alternatives to their traditional suppliers. Without long-term firm service, it is difficult for alternative suppliers to procure the financing they need for project development. Customers taking non-firm point-to-point service have a lower reservation priority and are subject to curtailment and interruption more frequently than network customers taking transmission service from resources other than designated network resources. Thus, the lack of long-term firm transmission access being provided on a nondiscriminatory basis is a significant problem in realizing the goals of Order No. 888.

304. The Commission's preliminary view is that current practices do not adequately reflect the manner in which transmission service is planned for bundled retail native load and may no longer be just, reasonable and not unduly discriminatory. Transmission customers, especially those customers seeking service to or from new generation resources, must be given greater flexibility of service to meet their needs comparable with the flexibility provided on behalf of bundled retail native load. New generation resources often face a grid that cannot accommodate requests for long-term firm transmission, at least not without the significant delay required by transmission construction, despite the fact that redispatch options may exist that would allow that resource to be accommodated. In sum, maintaining the status quo, as advocated by several commenters, may be insufficient to ensure comparable treatment of new generation resources for all transmission customers, eliminate barriers to entry for new generation sources seeking long-term transmission arrangements, and encourage the efficient and flexible use of the transmission system in a competitive market.

Proposed Solutions

305. The Commission believes there are two basic options for addressing this problem.[288] The first option focuses on generation redispatch to accommodate long-term firm point-to-point service, while the second option creates a modified form of firm point-to-point service that includes non-firm service in a defined number of hours of the year when firm point-to-point service is not available. The Commission's preliminary view is that the redispatch option is superior because it: (1) Mirrors the way that transmission providers plan for bundled retail native load, (2) would provide firm service to new entrants, rather than service that is subject to more frequent curtailment in certain hours of the year, and (3) may avoid certain implementation issues associated with designing a modified long-term point-to-point service. However, we seek comment on this preliminary view and on both of the options outlined below.[289]

Redispatch Service

306. The Commission believes that full utilization of generation redispatch is the preferred method of ensuring that long-term point-to-point service is not unduly discriminatory and does not serve as a deterrent to new entry. The preferred approach is described below.

307. Section 13.5 of the *pro forma* OATT requires the transmission

[285] *See pro forma* OATT section 27.

[286] Order No. 888 at 31,646.

[287] In 2004, electric generation from IPPs represented an increasing share of the wholesale markets with nearly 36 percent of total sales, a significant increase from 1996 when they accounted for only 12 percent of total sales. In 2004, IPPs accounted for 36 percent of generator nameplate capacity compared to 56.5 percent for utilities and 7.5 percent for combined heat and power. Office of Coal Nuclear Electric and Alternative Fuels, Energy Information Administration, Electric Power Annual 2004 at 9 (2005).

[288] We will continue to encourage transmission providers to propose other services requested by customers or such services that may meet their customers' and systems' needs as energy markets evolve. However, the Commission does not propose to require transmission providers to provide any service other than the services expressly set forth in the *pro forma* OATT. In response to EPSA, the decision to provide a new OATT service in the first instance remains with the transmission provider. Moreover, several of the proposals included in this NOPR such as lifting the price cap associated with capacity reassignment for firm point-to-point service and hourly firm point-to-point service should provide transmission customers with greater service flexibility.

[289] We also request comment on the applicability of these two options for transmission providers who operate RTOs or ISOs. Because RTOs provide redispatch service and the ability to access transmission with no prior reservation by paying congestion charges, they may not need to reform their existing procedures to satisfy our proposal with respect to redispatch. We also note that conditional firm service has the potential to disturb the link between long-term service and the allocation of Financial Transmission Rights (FTRs) or auctions of FTR rights.

provider to expand or upgrade its transmission system or, if it is more economical, to redispatch its resources to provide requested firm point-to-point service without: (1) Degrading or impairing the reliability of service to native load customers, network customers and other transmission customers taking firm point-to-point service; or (2) interfering with the transmission provider's ability to meet prior firm contractual commitments to others. The cost of any redispatch performed pursuant to section 13.5 is to be specified in the service agreement prior to initiating service and charged to the transmission customer consistent with Commission policy. For network service, section 33.2 of the *pro forma* OATT also requires all network customers to agree to redispatch their network resources, along with transmission provider's own resources, to relieve a constraint that may impair reliability. Section 33.3 of the *pro forma* OATT provides that the costs of reliability redispatch performed pursuant to section 33.2 are to be shared between network customers and the transmission provider on a load-ratio share basis.[290]

308. To encourage the provision of redispatch as an option to facilitate use of the existing transmission grid, we propose to revise the *pro forma* OATT to require the offer of redispatch prior to the performance of a facilities study. We note that the system impact study, as defined by the *pro forma* OATT, is the transmission provider's assessment of the adequacy of its grid to accommodate a request for firm point-to-point or network service and whether any additional costs may be incurred to provide the requested service. It is followed by a facilities study, which is defined as an engineering study to determine the transmission system modifications necessary to provide the requested service, including cost and scheduled completion date. Neither study references the steps necessary to evaluate the cost of redispatch that could be performed in lieu of expanding the grid. Therefore, we propose that the transmission provider must, as part of the system impact study process, include an estimate of the number of hours of redispatch that may be required to accommodate the request for transmission service, and a preliminary estimate of the cost of that redispatch. The customer would then be given the option of having the transmission provider perform the necessary studies to determine the projected redispatch costs or perform the facilities study, or both.

309. Consistent with the existing requirements of the OATT, the redispatch requirement would apply to the redispatch of the transmission provider's own generation resources and would not require the transmission provider to purchase new resources to provide this service.[291] However, we propose to require the transmission provider, when it cannot accommodate a long-term firm point-to-point transmission request through redispatch of its own resources, to identify the generators in other control areas that could relieve the constraint on the affected flowgates to allow the transmission customer to seek redispatch with transmission providers in adjacent control areas to remove such constraints. We also seek comment on whether to expand the existing OATT obligation to require the transmission provider to redispatch not just its own resources, but those of its network customers also, subject to the network customers receiving appropriate compensation when their resources are redispatched.

310. Another issue that arises is how the redispatch option should be priced. The *pro forma* OATT caps the cost of redispatch at the cost of constructing the network upgrades needed to facilitate the requested transmission service. Some commenters discuss what costs should be included in a redispatch rate, such as start-up costs, higher maintenance costs and fuel differentials, and state that inclusion of these charges would send clearer price signals and induce transmission investments.[292]

311. Establishing a formula rate for redispatch costs may be one way to ensure greater use of this option, both to facilitate long-term requests for service and to grant customers greater flexibility in choosing resources on a daily or hourly basis. A redispatch pricing proposal could include a MW quantity, the incremental cost of fuel (increasing the supply of fuel) at the point of delivery, and the decremental cost of fuel (decreasing the supply of fuel) at the point of receipt capped at the price of fuel. These costs could be calculated based on the difference between the cost of ramping up a generator at the point of delivery and ramping down a generator at the point of receipt.[293] We invite comments on whether including such a formula in the transmission provider's OATT would facilitate redispatch and whether it should account for other, hard-to-quantify costs such as those listed by EEI: Start-up costs, higher capital costs due to shorter life and accelerated replacement, higher maintenance costs, and potential emergency power purchases to serve load in constrained areas. One option might be to establish a standard per kWh fee for such costs, as was initially done for ancillary service costs.

312. There are few examples of functioning redispatch programs on which to base any kind of generic change to the *pro forma* OATT. However, the Commission has approved OATT provisions for SPP[294] (prior to its becoming an RTO) and Deseret.[295]

313. The redispatch provisions in SPP's OATT permitted a transmission customer facing a constrained path to decide whether to: (1) Go forward with its requested transmission service, (2) obtain relinquished capacity (solicit from holder of firm transmission rights the price at which they would relinquish their rights subject to the caps), (3) reduce transmission service to match the level of ATC without redispatch, (4) pay for redispatch, or (5) forego the transmission transaction.

314. Under Attachment H of SPP's OATT (Redispatch Procedures and Redispatch Costs for Short-Term-Firm Point-to-Point Transmission Service Subject to Redispatch Cost) the charges to be paid by the transmission customer for redispatch service could not exceed the charges the transmission customer would have paid under SPP's point-to-point tariffs. Stated differently, SPP capped the redispatch charges at a level

[290] Order No. 888–A at 30,267.

[291] However, we also request comment on whether it would be appropriate to require the transmission provider to contract to purchase generation from outside of its control area if it would facilitate a firm transaction. We note that at least one redispatch provisions currently in use contemplates the use of third-party generation for redispatch. *See* Deseret Generation and Transmission Cooperative, Inc. (Deseret) FERC Electric Tariff, First Revised Volume No. 2 (Deseret OATT), accepted for filing in *Deseret Generation and Transmission Cooperative, Inc.*, Docket No. ER01–2642–000 (Aug. 27, 2001) (unpublished letter order). Attachment J of Deseret's OATT states, in part: ''If redispatch services are provided under this Attachment J, the [t]ransmission [p]rovider will in good faith attempt to relieve the constraint by the least-cost means, whether by seeking a change in generation output from the [t]ransmission [p]rovider's [m]erchant [f]unction *or from any other feasible generator* or by other means including facilitating the payment of firm transmission customers to temporarily give up their rights to relieve the constraint.'' Deseret OATT, Attachment J, Part I.D, Original Sheet No. 340 (effective July 1, 2001).

[292] *E.g.*, Ameren, EEI, Progress Energy, and Southern.

[293] For example, redispatch costs = 75 MW × ($60 incremental cost at the point of delivery − $15 decremental cost at the point of receipt) = $3,375.

[294] *See Southwest Power Pool, Inc.*, 82 FERC ¶ 61,267, *modified*, 82 FERC ¶ 61,285, *order on reh'g*, 85 FERC ¶ 61,031 (1998); *Southwest Power Pool*, Inc., 84 FERC ¶ 61,055 (1998).

[295] *See supra* note 291.

that ensures that total charges did not exceed the total charges the customer would have paid under individual company tariffs. For generation resources, the redispatch included the higher of incremental or replacement fuel costs and incremental operation and maintenance costs of generation facilities necessary to relieve constraints on the transmission system.

315. The redispatch provisions in Deseret's OATT are designed to track cost causation with redispatch costs and contains features similar to the SPP OATT provisions such as providing customers with the opportunity to obtain relinquished capacity. Like SPP, the redispatch costs in Deseret's OATT are capped at the cost incurred by the transmission provider to provide the requested service. Under Attachment J of Deseret's OATT (Redispatch Protocol), generally the redispatch costs are calculated by multiplying the redispatch quantity, in MWh, that is required to satisfy the transmission customer's schedule in that hour by the redispatch price. Attachment J of Deseret's OATT also includes provisions for crediting and netting of redispatch costs.

316. We also are concerned that there is a great deal of complexity and fuel price risk in projecting years into the future the hours of redispatch that will be required to grant the transmission request and the cost of that redispatch in those hours. Moreover, because of the need for involvement of the transmission provider's generation arm to project costs associated with redispatch and the need to factor in unpredictable fuel costs, we are concerned about the degree of discretion involved in determining redispatch costs. Understandably, the transmission provider does not want to bear the price risk associated with projected fuel costs, nor does the customer. PacifiCorp, in its comments, describes a possible proposal that would calculate redispatch costs monthly and charge the higher of redispatch or the OATT rate each month. We request comment on whether PacifiCorp's proposal may be a way of addressing the complexity and risk associated with determining redispatch costs over a long period and allow greater access to otherwise unused transmission capacity on a firm basis.

317. We ask for comment on whether all or a portion of SPP's, Deseret's, or PacifiCorp's proposals should form the basis for a generic redispatch provision that could be included in the *pro forma* OATT, as a means of ensuring that redispatch service is available and priced on a just and reasonable basis.

318. Finally, we recognize that a transmission provider may need to coordinate with marketing affiliate or energy affiliate employees to arrange generation redispatch.[296] However, such communication and coordination raise potential problems for the transmission provider regarding compliance with the Commission's Standards of Conduct, which require separating transmission function employees from wholesale marketing and energy affiliate employees.[297] We seek comment on what communication and coordination protocols can be established to permit the provision of generation redispatch in a manner that is not unduly discriminatory or preferential, and consistent with the Standards of Conduct.

Conditional Firm Service

319. The Commission seeks comment on whether a modified form of long-term point-to-point service would be preferable to the redispatch service described above. This conditional firm service option would address the problem of reliability limitations during certain peak hours by allowing the transmission provider to provide non-firm service to the customer in those hours. We note that at least one transmission provider currently provides this service pursuant to amendments to the partial interim service provision of its OATT,[298] with only modest differences from the service described below.

320. As an initial matter, in response to requests for clarification of the partial interim service in section 19.7 of the *pro forma* OATT, we will summarize the Commission's precedent on this service. The Commission has clarified that partial interim service has a partial duration element, as well as a partial quantity element.[299] For example, in *Morgan Stanley*, the Commission found that had the customer requested long-term service for a two-year period, but only one year was available, the transmission provider would have been obligated to offer service for that one available year.[300] The Commission was clear, however, that partial interim service does not require the transmission provider to treat a request for annual service as if it necessarily included a request for all subsumed monthly or weekly durations of service during the requested year.[301] In other words, a transmission provider does not need to respond to a request for one year of service with an offer of monthly service. The Commission has also interpreted section 19.7 to apply to requests for transmission service that have not undergone or do not necessarily require a system impact study or facilities study.[302] Further, the Commission has required transmission providers to offer partial interim service even where third-parties must provide upgrades in order to provide for the full transmission service request.[303] Although partial interim service has a duration component, it differs from conditional firm service, which would require the transmission provider to treat the request for service as if it included a request for monthly, weekly, daily, and hourly firm service during the year.

321. If we decline to adopt the redispatch proposal above, any conditional firm service that we would order would be made available only to customers who request long-term firm point-to-point service. When the long-

[296] In this discussion, we use the terms ''transmission function,'' ''marketing affiliate'' and ''energy affiliate'' as those terms are used in the Standards of Conduct regulations. *See* 18 CFR 358.3 (2005).

[297] *See* Order No. 2004 at P 85–94.

[298] *See PacifiCorp*, 98 FERC ¶ 61,224 at 61,885 (accepting revisions to section 19.7), *order on reh'g*, 99 FERC ¶ 61,259 (2002).

[299] *See, e.g., Idaho Power Co.* v. *Bonneville Power Administration*, 96 FERC ¶ 61,031 at 61,080–81 (2001) (*Idaho Power* v. *Bonneville*) (interpreting section 19.7 to require Bonneville to offer 277 MW of monthly short-term firm transmission capacity interim service to the entity next in the queue with a request of 577 MW); *Morgan Stanley Capital Group* v. *Illinois Power Co.*, 93 FERC ¶ 61,081 at 61,220 (2000) (*Morgan Stanley*) (''Illinois Power should have offered as much transmission capacity as it could provide continuously for the duration of the request, *i.e.*, as many MW of transmission service as available for the entire one-year period Morgan Stanley requested.''); *accord Idaho Power Co.*, 90 FERC ¶ 61,009 at 61,018–19 (2000) (directing transmission provider to provide 18 months of partial interim service for a customer requesting eight years of service).

[300] *Morgan Stanley* at 61,220. In response to Bonneville, the Commission clarifies that a customer does not lose its queue position for its original request when it accepts a counteroffer for less service than originally requested.

[301] *Id.* at 61,220; *Tenaska Power Services Co.* v. *Southwest Power Pool, Inc.*, 93 FERC ¶ 61,082 at 61,222–23 (2000) (both concluding that transmission provider has no obligation to respond to a long-term request with an offer of short-term service).

[302] *See, e.g., Idaho Power* v. *Bonneville* at 61,080–81 (requiring an offer of partial interim service for short-term firm service where a system impact study is not applicable); *Morgan Stanley Capital Group* v. *Illinois Power Co.*, 83 FERC ¶ 61,204 at 61,912 (ordering partial interim service without requiring a system impact study or facility study), *clarification granted*, 83 FERC ¶ 61,299 (1998), *reh'g granted in part*, 93 FERC ¶ 61,081 (2000).

[303] *Bonneville Power Administration*, 110 FERC ¶ 61,001 at P 36–37 (directing Bonneville to offer to provide customer with whatever portion of the request it could provide on a firm basis after the customer's generation project was energized without upgrades to PacifiCorp's system and to amend the agreement after upgrades are completed to provide for the full amount), *reh'g denied*, 110 FERC ¶ 61,094 (2005).

term firm point-to-point service is not available, and the customer requests conditional firm service, the transmission provider would evaluate transmission availability for the portion of the long-term request that cannot be filled due to lack of ATC. The evaluation of conditional firm availability should occur prior to a system impact study or facilities study. In offering conditional firm service, the transmission provider must identify the number of hours during the year in which the conditional firm customer will have service identical to any other firm point-to-point service, and specify the maximum number of hours of the year during which firm transmission service may be unavailable. The conditional firm service agreement would identify the conditional curtailment hours, *i.e.*, the number of potential hours during those conditional times when the customer could have its reservations cut or reduced prior to any firm customer reductions. Conditional firm service would include an annual cap to the conditional curtailment hours and we seek comment on whether it should also include monthly caps for each conditional month. Capacity commitments for conditional firm service would be accounted for in the ATC calculations prior to new sales of short-term firm transmission service, thus not degrading the value of the conditional firm transmission product.

322. We propose that conditional firm service would be curtailed before firm uses until such time as curtailment of the conditional firm service has reached the annual or monthly caps, after which time the service would be treated as firm. We propose that conditional firm service, during conditional curtailment hours, be treated equivalent to secondary network service.[304] We decline to adopt the proposed quasi-firm curtailment priority because it would require creation of a new curtailment classification including a determination concerning the appropriate type of curtailment, *i.e.*, choosing between *pro rata* curtailment currently used for firm transactions or full transaction curtailment currently used for non-firm transactions. Institution of a new curtailment class would require changes to curtailment protocols and reliability coordinators' procedures, which is potentially burdensome and costly. Further, as discussed below, we believe that conditional firm point-to-point service, as proposed, is analogous to the secondary network service currently used by network customers and therefore both services should enjoy the same curtailment priority.

323. We propose that customers pay the long-term firm point-to-point rate for conditional firm service and have a right of first refusal when firm service becomes available for the hours in which they have agreed to be curtailed. This rate for conditional firm service is consistent with the Commission's pricing policies that promote maximization of long-term uses of the grid. Also, this rate makes this service more equivalent to secondary network service because network customers using secondary network service already have paid for the long-term use of the grid. Further, it avoids gaming incentives that a discounted rate could provide. For example, a discounted rate might provide incentives for customers to request a year of service where they know only three months of service is available. We seek to prevent this type of gaming by requiring the payment of a long-term firm rate. In this regard, we also expect that the long-term firm point-to-point rate will tend to limit the type and number of requests for conditional firm service. Customers will weigh the value of the service, including the probability of curtailment, against the cost of paying the full long-term firm rate, in deciding whether to queue for conditional firm service where customers earlier in the queue are offered, for example, 50, 100 or 150 conditional curtailment hours.

324. Further, we propose that customers with conditional firm service would qualify for rollover rights provided that they meet the other rollover right conditions proposed herein. The service agreement for conditional firm service would specify the number of conditional curtailment hours. The transmission provider would not be required to plan for service to the conditional firm customer during the conditional curtailment hours. We seek comment on the application of rollover rights to the conditional firm service.

325. The Commission is not convinced that it is necessary to make this service available to network customers. Network customers enjoy flexibility that point-to-point customers do not, given the ability of network customers to use secondary network service to access resources other than designated resources on an as-available basis under section 28.4 of the *pro forma* OATT. For example, if a network customer's request to designate a new network resource was denied due to lack of ATC, the network customer could seek secondary network service for the resource and receive service on an as-available basis. Such service would be curtailed only after all non-firm point-to-point uses sharing the same flowgate were curtailed. This is similar to the service that we now propose for point-to-point customers in the form of conditional firm service. We therefore tentatively conclude that conditional firm service is not needed by network customers, though we seek comment on that preliminary finding.[305]

326. We acknowledge that the obligation to provide conditional firm service may require the transmission provider to model its transmission system and the uses of its system with greater specificity. We recognize that all transmission providers do not use a single standard engineering approach to evaluate firm transmission service requests: some transmission providers have a single powerflow base case for each year studied; some use a single base case powerflow model to represent several future years; and others may have several seasonal base case powerflows for the study of future years. Transmission providers also use different methods to establish generator dispatch for input into the powerflow base case models: some transmission providers use heat-rates without fuel prices for determining generator output in future years' models; some use economic unit commitment order; and others use projected fuel prices to establish base case powerflow generation output. Some transmission providers use an economic dispatch model to determine unit dispatch prior to establishing powerflow base cases. Additionally, some transmission providers must take into account environmental considerations, such as the pricing of emissions allowances, in establishing generator output for powerflow base case models.

327. Regardless of the engineering approach used, in responding to a conditional firm request, the transmission provider would need to specify for the requesting customer the number of hours of firm service available in the year for each MW of firm service requested. This may require

[304] Secondary network service (section 28.4 of the *pro forma* OATT) refers to transmission service for network customers from resources other than designated network resources provided on an as-available basis. Section 14.7 of the *pro forma* OATT provides that secondary network service is curtailed or interrupted before firm network or point-to-point service but after non-firm point-to-point service.

[305] Network customers pay for long-term use of the system and should maintain priority use of the system for secondary network service over those paying for non-firm use. However, because conditional firm customers will pay for long-term use, they should also maintain, for the conditional curtailment hours, a curtailment priority over non-firm uses equal to the curtailment priority for secondary network service.

that the transmission provider produce and examine additional powerflow cases or make other process changes. In order to determine the number of hours that the requested firm transmission capacity is unavailable, the transmission provider may need to model varying load conditions, generation and transmission planned outages, and time-contingent or condition-contingent generation dispatches. Generally, the greater the number of conditions studied, the lower the risk to the transmission provider of an inaccurate estimate of conditional curtailment hours. We recognize that there are limits to the accuracy of any prediction of hours of curtailment, no matter how detailed the system study.

328. There are a number of ways for a transmission provider to determine the number of hours in a year when firm service is unavailable, *i.e.*, the conditional curtailment hours. One method involves scaling down the powerflow base case. Using this method, the transmission provider could scale down the load and generation in the base case until the entire conditional firm request is available on the studied flowgate. For example, a base case might need to be scaled down to 95 percent of the summer peak demand in order to accommodate the conditional firm request as firm point-to-point service. The transmission provider would then calculate the number of hours the seasonal load is forecast to be 95 percent or higher to come up with the number of seasonal hours of curtailment for the conditional firm customer.

329. Another method involves an inventory of generation and demand shift factors. Using this method, the transmission provider could determine conditional curtailment hours by adding up all the outstanding generation and load shift factors on the relevant flowgate. Once the transmission provider determines the load shift factor on the flowgate, it can calculate the reduction needed in regional demand to accommodate the conditional firm request by comparing the impact of the request on the power flows. The demand reduction would not necessarily correspond perfectly with the requested amount of service. For instance, a 200 MW reduction might be required to accommodate a 100 MW conditional firm request. Once the transmission provider determines a reduced load level that would accommodate the conditional firm request, the transmission provider would examine load forecasts to calculate the number of hours the load is expected to exceed this reduced load level. This alternative method of calculating conditional curtailment hours might be more burdensome than scaling down the powerflow base case because it requires additional data collection and analysis.

330. Both of these methods rely on average system conditions and do not take into account extreme weather years or unexpected outages. Thus, the methods would provide an optimistic view of bulk power facility availability. These methods can be used to determine the portion of time (hours) that transmission capability will most likely be available and give general information on when (seasons, months) firm service is available.

331. We seek comment on the most appropriate method of modeling the transmission system to determine the number of conditional curtailment hours. We also recognize that additional studies may cause additional costs. We seek comment on methods of ensuring recovery of these additional costs.

332. We also acknowledge that provision of conditional firm service may require some modification to current transaction tracking procedures in use by the industry and require development of additional mechanisms. Today, transmission providers track transactions with curtailment priorities so that when congestion occurs transactions are curtailed consistent with OATT requirements, *i.e.*, non-firm uses are cut before firm uses and short-term transactions are cut before longer-term transactions. In order to implement the conditional firm service, transmission providers would need to determine in advance of scheduling deadlines whether the service should be tracked as a long-term firm use or to reflect the use of the conditional curtailment hours.[306] If the service is treated as firm during a certain period, the transaction would not be cut before other firm uses. The transmission provider would have to perform a calculus, taking into account forecast load and transmission and generation availability, to determine the need to cut the conditional firm transaction in the next period prior to scheduling the transaction as conditional firm. While we do not view this as an insurmountable problem, we note that the decision to curtail a conditional firm transaction prior to other firm uses simply cannot be made in real time. We also note that the transmission provider would need to develop a mechanism to track the number of annual conditional curtailment hours in each service agreement and its annual or monthly use of those hours. Such a tracking mechanism would ensure that the transmission provider did not exceed the annual or monthly cap on conditional curtailment hours in any particular service agreement.

[306] We propose that during conditional curtailment hours, the transaction would be tagged with the network non-firm tag (currently used for secondary network service).

2. Hourly Firm Service

333. The *pro forma* OATT contains a one-day minimum term for firm point-to-point service. In Order No. 888, the Commission chose a one-day minimum over a one-hour minimum because of concerns expressed by commenters.[307] There, commenters argued that comparability would not be achieved if some point-to-point customers were permitted to take service for one hour and receive the same priority as native load and other long-term customers that have to pay the fixed cost of the transmission system every hour of the year. They also expressed concern that a one-hour minimum term for firm point-to-point service (hourly firm) would promote selective use of the transmission system, impair the ability of a utility to plan its system, and adversely affect longer term transactions. Finally, some expressed concern that a one-hour firm service may encourage speculative requests for service during the system peak day (a practice known as ‘‘cream skimming’’).

334. In the NOI, the Commission noted that several public utility transmission providers have individually filed for and received Commission authorization to modify their OATTs to provide hourly firm point-to-point service.[308] In the NOI, the Commission sought comment on whether the concerns expressed in Order No. 888 remain valid, and whether hourly firm service should now be required. The Commission also asked whether hourly firm requests should be batched to allow the transmission provider to evaluate them as if they were a single request, and whether scheduling timelines for firm and non-firm hourly transmission service should differ.

Comments

335. Some commenters support requiring transmission providers to

[307] Order No. 888 at 31,752.

[308] The NOI cited *Entergy Services, Inc.*, 85 FERC 61,163 (1998), *order on reh'g*, 91 FERC 61,153 (2000) and *El Paso Electric Co.*, Docket No. ER04–567–000 (Apr. 9, 2004) (unpublished letter order).

adopt hourly firm service.[309] Alberta Intervenors and TransAlta argue that hourly firm service encourages trade and market liquidity. Regarding the concerns cited in Order No. 888, EPSA argues that, as a practical matter, daily firm service already receives an equal priority to native load and other long-term customers, and none of the concerns expressed in Order No. 888 have materialized. ''Cream skimming'' should not be a problem, EPSA continues, because firm transmission reservations are not cost-free, and transmission customers are unlikely to commit financial resources for speculative purposes. Constellation argues that there should be no concern that comparability will be eroded because hourly firm service provides additional flexibility to the competitive markets. PPL argues that in non-ISO/RTO regions like the western United States, hourly firm service could help to maximize the use of existing transmission facilities, increase efficiencies in wholesale markets, and allow customers to purchase only the amount of firm transmission service that they need.

336. Some commenters offer qualified support for hourly firm service.[310] For example, South Carolina E&G states that before the Commission requires hourly firm service, it should obtain empirical market information on transmission providers' ability to provide such service. In its reply comments, Powerex explains that there is a potential for a detrimental effect if a transmission provider is not able to accurately determine its ATC, and before making hourly firm service mandatory, the Commission should ensure that the rights of long-term firm customers will not be negatively affected.

337. Among commenters who oppose requiring the adoption of hourly firm service,[311] many repeat arguments that appeared in Order No. 888. For example, several commenters express concern that hourly firm service will lead to ''cream skimming,'' result in unfairness to longer-term firm transmission customers who would have to be curtailed pro rata along with customers who have only made hourly firm commitments, or create inefficiencies by having a higher reservation priority than subsequently submitted load-based services such as secondary network service.[312] But other commenters who oppose requiring hourly firm service state that the concerns expressed in Order No. 888 may no longer be a major problem, and may be addressed by allowing hourly firm service to be pre-empted by longer term firm service requests.[313]

338. TVA argues that reservations for hourly firm service would nearly always end up being bumped by requests for longer service and as such would waste valuable time and increase administrative costs with no real benefit.

Processing

339. On the issue of whether a transmission customer should be permitted to batch requests for service, those in favor generally state that batching allows for greater efficiencies.[314] For example, Bonneville states that batching in the hourly market would decrease the response time for all requests in the hourly queue. Salt River states that a potential customer should be able to submit a batch of requests (*e.g.*, a block of hours) that is useful in shaping the service to its load-serving needs. Snohomish states that in the day-ahead schedule submittals, batching of hourly firm transmission requests for evaluation as a single request should be permitted, but for periods prior to day-ahead, batching of hourly requests should not be allowed due to the potential for ''cream skimming.''

340. Among those opposed to or expressing reservations regarding batching, Ameren and EEI argue that transmission providers already have the ability to process multiple requests from the same party, but they caution that batching requests for simultaneous modeling purposes (*e.g.*, transmission from points A to B and B to A simultaneously) would be difficult to implement. WAPA states that, in its experience, the majority of hourly firm transmission requests must be uniquely identified and evaluated for potential conflicts with longer-term firm transmission requests.

Scheduling

341. The *pro forma* OATT currently requires that schedules for firm and non-firm service be submitted on different timelines. Schedules for hourly non-firm point-to-point service must be submitted to the transmission provider no later than 2 p.m. the day before service is to commence.[315] For all firm services, schedules must be submitted to the transmission provider no later than 10 a.m. the day before service is to commence.[316]

342. Some commenters argue that firm and non-firm hourly services should be subject to the same scheduling timeline.[317] To do otherwise, Snohomish argues, would be administratively burdensome and without benefit to the transmission provider or transmission customer. Those arguing for different scheduling timelines generally argue that the scheduling time-frames for firm and non-firm transmission service should remain different, at least on a pre-schedule or day-ahead basis, because the transmission provider must know the full extent of firm utilization before non-firm offerings can be determined.[318]

Discussion

343. The Commission proposes to add point-to-point hourly firm service to the *pro forma* OATT because it will eliminate a barrier to the development of markets and thereby decrease opportunities for undue discrimination. The terms of service we propose will ensure that hourly firm customers are offered service in a manner consistent with comparability principles, and pay their fair share of system costs. We conclude that hoarding and speculation should not be a major concern because requests for hourly firm service are subject to preemption by longer-term requests for service. We also conclude that the provision of hourly firm should have no effect on investment in the grid because a transmission provider does not plan its system to meet hourly firm, or any other short-term firm, transmission requests. In addition, the expected effect of hourly firm on long-term transactions is no different than the effect of other short-term firm services. For example, though commenters are correct that hourly firm will be curtailed pro rata with longer term firm point-to-point service, this is already true of daily firm point-to-point service. As noted in the NOI, many transmission providers already offer this service and there appear to be no technical impediments to offering it, nor have customers on these systems

[309] *E.g.,* Alberta Intervenors, Alcoa, Calpine, Constellation, EPSA, HQ Energy, PPL, and TransAlta.

[310] *E.g.,* APPA, Northwestern, Powerex, Public Power Council, Salt River, and South Carolina E&G.

[311] *E.g.*, Ameren, APS, Duke, EEI, KCP&L, LG&E, LPPC, MidAmerican, NRECA, Progress Energy, Snohomish, Southern, TAPS, TVA, TDU Systems, and WAPA.

[312] *E.g.*, LG&E, Progress Energy, Southern, and TAPS.

[313] *E.g.*, EEI and WAPA.

[314] *E.g.*, Alberta Intervenors, Bonneville, Constellation, EPSA, and South Carolina E&G.

[315] *See pro forma* OATT section 14.6 (also allowing schedules to be submitted by a reasonable time that is generally accepted in the region).

[316] *See pro forma* OATT section 13.8 (also allowing schedules to be submitted by a reasonable time that is generally accepted in the region).

[317] *E.g.*, Ameren, Constellation, PNM–TNMP, Powerex, Salt River, Snohomish, and South Carolina E&G.

[318] *E.g.*, Ameren, Northwestern, and Southern.

expressed any concern about the effect of hourly firm on long-term firm services or curtailments. Therefore, we conclude that the concerns expressed in Order No. 888 regarding unduly discriminatory effects of hourly firm service have proven unfounded, and we propose that hourly firm service be a required offering in the *pro forma* OATT.

344. As for the pricing of hourly firm service, consistent with Commission precedent, we propose to use the ''*IES* Method'' and apply different pricing for hourly firm service based on whether the service is taken during peak or off-peak hours.[319] Pricing for hourly firm service during peak periods would be based on 4,160 hours annually of peak usage over 52, 5-day weeks of 16-hour days ($52 \times 5 \times 16 = 4{,}160$), rather than all 8760 hours of the year. In other words, the rate is derived from the hours during which the facilities are likely to be used, rather than the total hours in the year. It is premised on the assumption that a customer using the transmission system for the 16 peak hours of the day should pay the same contribution to fixed costs as a customer who has reserved capacity on a daily basis.[320] But because hourly service is unlikely to be taken only during peak hours, we propose to allow pricing for hourly firm service for off-peak hours based on 8,760 hours of usage.[321] This is appropriate because customers using short-term service during off-peak hours do not constrict the system during the peak period, and should pay less than what they pay during the peak period.[322] To ensure that hourly customers do not pay more than their fair share of fixed costs, consistent with the pricing principles set forth in Order No. 888, the total charge in any day for hourly service cannot exceed the stated daily rate multiplied by the maximum hourly capacity reservation during such day.[323] We conclude that using the *IES* Method to price hourly firm service at a higher rate during peak periods will ensure that hourly firm customers pay a fair share of the costs of the transmission system and, as a result, mitigate ''cream-skimming'' concerns.

345. As for allowing transmission customers to batch requests for service, we conclude that allowing such batching creates administrative efficiencies for the transmission customer and transmission provider alike. Therefore, we propose allowing transmission customers to batch requests and schedules for hourly firm service that will be provided within the same day.

346. The Commission also concludes that the current scheduling practices can accommodate the scheduling of hourly firm transmission service. To require that both firm and non-firm hourly services be scheduled at the same time would require that the existing procedures be revised, with no discernible benefit to the transmission customer or transmission provider. Even with the addition of this new service, it remains reasonable to require that the transmission provider have all firm schedules at the same time, and in advance of the deadline for non-firm schedules. Therefore, we propose that schedules for firm hourly service, like all other firm schedules, will be due by 10 a.m. the day before the service is to commence.

347. Finally, we propose that, consistent with other durations of service, the confirmation period for hourly firm service specified in section 13.2 of the *pro forma* OATT will allow longer-term requests for service to preempt shorter hourly firm requests for service until one hour before the commencement of hourly firm service.

3. Rollover Rights

348. Section 2.2 of the *pro forma* OATT allows existing firm transmission service customers—wholesale requirements and transmission-only customers with contracts of one year or more—the right to continue to take transmission service from the transmission provider when the customer's contract expires, rolls over or is renewed. The *pro forma* OATT provides that the transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the transmission provider or elects to purchase capacity from another supplier. This transmission reservation priority for existing firm transmission service customers, which is also referred to as a right of first refusal or a rollover right, is an ongoing right that may be exercised at the end of all firm contract terms of one year or longer. A transmission customer must give notice of whether it will exercise its right of first refusal 60 days before the expiration of its service agreement.

349. In Order No. 888, the Commission provided that, if a transmission customer subject to the rollover right selects a new power supplier that substantially changes the location or direction of its power flows, the customer's right to continue taking service from the transmission provider may be affected by transmission constraints associated with the change.[324] The Commission also provided that a transmission provider may reserve existing capacity for retail native load and network load growth reasonably forecasted within the transmission provider's current planning horizon, but that any capacity so reserved must be posted on the transmission provider's OASIS and made available to others until the capacity is needed for the anticipated network or retail native load use.[325] The Commission also has held that a transmission provider may restrict a right of first refusal based on pre-existing contracts that commence in the future if the transmission provider knows at the time of the execution of the original service agreement that ATC used to serve a customer will be available for only a particular time period, after which time it is already committed to another transmission customer under a previously confirmed transmission request.[326] Once a

[319] The Method is named for a proceeding in which peak and off-peak pricing was applied to hourly non-firm transmission service. *IES Utilities, Inc.,* 81 FERC ¶ 61,187 at 61,833–34 (1997), *reh'g denied,* 82 FERC ¶ 61,089, *aff'd on other grounds sub nom, Wisconsin Public Power Inc.,* v. *FERC,* 1999 U.S. App. LEXIS 3998 (Feb. 23, 1999) (unpublished opinion); *see New York State Electric & Gas Corp.,* 92 FERC ¶ 61,169 at 61,593–94(2000) (approving application of the *IES* Method for time-differentiated hourly non-firm rate design), *order on reh'g,* 100 FERC ¶ 61,021 (2002).

[320] Peak period pricing is referred to as the ''*Appalachian* Method'' or ''AEP Method,'' and takes its name from the proceeding in which it originated. *Appalachian Power Co.,* 30 FERC ¶ 61,296 (1987). The *Appalachian* Method is consistent with the premise that firm transmission service be priced based on the system's peak periods of usage. *See Entergy Services, Inc.* 85 FERC ¶ 61,163, at 61,645 (1998) (approving application of the method for firm service on an hourly basis during peak hours), *reh'g denied,* 91 FERC ¶ 61,153 (2000).

[321] *See IES Utilities, Inc.,* 81 FERC at 61,833–34 (approving use of an 8,760 hour year to calculate rates for non-firm service on an hourly basis during off-peak hours); *Entergy Services, Inc.,* 85 FERC at 61,645 (approving use of an 8,760 hour year to calculate rates for firm service on an hourly basis during off-peak hours).

[322] *Appalachian Power Co.,* 39 FERC at 61,965; *see American Electric Power Service Corp.,* 88 FERC ¶ 61,141 at 61,453–54 (1999).

[323] And, in turn, the total demand charge in any week pursuant to a reservation for hourly or daily service cannot exceed the weekly rate multiplied by the maximum hourly capacity reservation in any hour during such week. *See pro forma* OATT schedules 7 and 8; *see also Entergy Services, Inc.,* 85 FERC ¶61,163 at 61,645 (1998) (applying these principles to a proposal for firm service on an hourly basis), *reh'g denied,* 91 FERC ¶61,153 (2000).

[324] Order No. 888 at 31,665 n.176.

[325] *Id.* at 31,694.

[326] *E.g., Southwest Power Pool, Inc.,* 109 FERC ¶ 61,041 at P 6 (2004).

transmission provider evaluates the impact on its system of serving a long-term firm transmission customer and grants the transmission customer existing capacity, the transmission provider must plan and operate its system with the expectation that it will continue to provide service to the transmission customer should the transmission customer exercise the right of first refusal. If constraints arise after a transmission provider enters into a long-term agreement with the transmission customer (and that agreement does not contain an allowed restriction on the transmission customer's right of first refusal), the obligation is on the transmission provider to determine whether or not to build additional facilities to accommodate new transmission customers.[327] A transmission provider is obligated to curtail service pursuant to its OATT or expand its system when its system becomes constrained such that it cannot satisfy existing transmission customers, including the exercise of their rollover rights, because it should have planned and operated its system with the expectation that each long-term firm transmission customer will exercise its rollover rights.[328]

350. If a transmission provider's transmission system cannot accommodate all of the requests for transmission service at the end of the contract term, the existing long-term transmission customer must agree to match the rate offered by the potential customer, up to the transmission provider's maximum rate, and to accept a contract term at least as long as that offered by the potential customer. However, a competitor's offer does not have to be ''substantially similar in all respects'' to the existing transmission customer's.[329]

The NOI

351. In the NOI, the Commission sought comment on whether transmission providers have hindered transmission customers under pre-Order No. 888 agreements from rolling over their contracts that allow purchase of capacity and energy from another supplier. The Commission also asked whether the language in section 2.2 of the *pro forma* OATT needs to be reformed to ensure that rollover rights are provided when transmission customers are seeking access to alternative supply sources, or whether the issue was an enforcement matter. The Commission sought comment on whether the rollover right policy determinations made subsequent to Order No. 888 should be included in the *pro forma* OATT. The Commission inquired whether there were other problems with section 2.2, either as written or as implemented by transmission providers, that need to be addressed. The Commission also asked whether potential transmission customers are denied transmission access by the exercise of rollover rights. Finally, the Commission asked whether it should reconsider the concept of rollover rights and whether the one-year service with rollover rights is consistent with the need to create incentives for transmission investment or should a longer minimum term of service be adopted to qualify for rollover rights.[330]

Comments

352. Many transmission providers and APPA argue that, because a transmission provider may not know until 60 days prior to termination whether a contract would be renewed, rollover rights in contracts as short as one year inhibit the ability of transmission providers to plan their systems.[331] Transmission providers also argue that the right of first refusal results in the denial of transmission that leads to an inefficient use of transmission capacity.[332] They explain that the transmission provider must hold back capacity from the market for existing transmission customers that have a right of first refusal but that have not yet indicated whether they intend to exercise it. By the time the termination notice is given, other transmission customers that may have wanted to reserve the newly freed capacity have been turned away and have made other arrangements. They assert that the result is an inefficient use of capacity. In addition, these transmission providers argue that the 60-day notice provision does not allow them adequate time to re-market any capacity when it is freed-up by the terminating customer. Further, certain transmission providers argue that the right of first refusal unfairly gives transmission customers a valuable ''free call option'' on transmission capacity without any obligation to take the capacity at the end of the contract or to compensate the transmission provider for the value of the option.[333] To avoid these problems, many transmission providers suggest that the rollover right should apply to firm transmission contracts with minimum terms of between two and ten years.[334] In addition, these commenters suggest that, if the Commission lengthens the term of the firm contracts eligible for the right of first refusal, the 60-day renewal provision also should be extended.

353. Certain transmission customers argue that the Commission should retain the right of first refusal in its present form, or change it only after the Commission requires regional planning or other events occur.[335] Transmission customers stress the need for the rollover rule as a means to ensure long-term service. According to Constellation, transmission customers subject to rollover rights are not temporary customers but are long-term customers that happen to take their service under year-to-year agreements. Likewise, EPSA asserts that rollover rights are important in planning for the long-term needs of loads and generation located on the grid and that ''the ability to roll over a firm transportation contract (by matching the contract term and the rate of competing shippers) is the only way that market participants can ensure that their needs will be met.''

354. Numerous commenters address the impact of native load growth on the right of first refusal rule. As previously indicated, the Commission permits transmission providers to restrict a firm transmission customer's right of first refusal based on the transmission provider's reasonable projections of native load growth. Several commenters argue, however, that the Commission has not provided adequate guidance as to the information a transmission provider must submit to demonstrate native load growth.[336] Further, commenters argue that the Commission should allow transmission providers a means to update their native load data to address any load growth that was not anticipated at the time of the original contract. In addition, some commenters argue that the Commission's rejection of native load growth projections in prior cases, and the provision for pro rata curtailment of service in the event of capacity shortfalls due to the exercise of a right of first refusal, fail to respect the native load preference adopted in Order No. 888, as well as in section 217 of the FPA as added by section 1233 of EPAct

[327] *Id.* at P 9.

[328] *Id.*

[329] *Idaho Power Co.* v. *FERC,* 312 F.3d 454, 462 (D.C. Cir. 2002).

[330] NOI at P 18.

[331] *E.g.*, APPA, Bonneville, Duke, LPPC, Nevada Companies, Progress, and Salt River.

[332] *E.g.*, Ameren, Duke, EEI, North Carolina Commission, Santa Clara, and South Carolina E&G.

[333] *E.g.*, Ameren, Entergy, and Nevada Companies.

[334] *E.g.*, APPA, Bonneville, Cinergy, LDWP, MidAmerican, Nevada Companies, Progress, Santee Cooper, South Carolina E&G, and Southern.

[335] *E.g.*, AMP-Ohio, Calpine, Constellation, and EPSA.

[336] *E.g.*, Duke, EEI, Entergy, Nevada Companies, Progress Energy, Santee Cooper, and Salt River.

2005. They argue that new section 217 of the FPA reverses Commission precedent that limits the ability of transmission providers to recall capacity for native load once it is subject to a right of first refusal.

Discussion

355. The comments filed in response to the NOI demonstrate a need to retain, but revise, the right of first refusal provision in the *pro forma* OATT. The Commission proposes to revise the right of first refusal provision in the *pro forma* OATT to apply to wholesale requirements and transmission-only contracts that have a minimum term of five years, rather than the current minimum term of one year. In addition, the Commission proposes that a transmission customer under a rollover agreement must provide notice of whether or not it will exercise its right of first refusal no less than one year prior to the expiration date of the transmission service agreement. We agree with APPA that these changes strike an appropriate balance between providing customers meaningful rollover rights and encouraging long-term contracting, new investment and long-term planning. Finally, if the existing customer seeks to exercise its rollover right and there is insufficient transmission capacity on the system at the end of the contract term to accommodate all of the requests for transmission service, the existing customer would have to agree to accept a contract term at least equal to a competing request by any new customer or five years, whichever is longer, and to pay the current just and reasonable rate, as approved by the Commission, for such service.

356. The Commission's proposal is consistent with the transmission customers' comments that the right of first refusal should be designed to ensure long-term service. Extending the minimum term of the right of first refusal agreements to five years will encourage long-term use of the grid. In addition, the one-year prior notice requirement should allow adequate time for transmission providers to re-market unused capacity that may result from a transmission customer choosing not to roll over a service agreement. The one-year notice provision also should limit the instances when the transmission provider must turn away a transmission request only to find out that it could accommodate the request after the transmission customer elected not to roll over. These changes should result in a more efficient use of the transmission grid.

357. If we adopt the proposed minimum five year/one year right of first refusal provision in the *pro forma* OATT, we propose to allow this provision to become effective upon Commission acceptance of the transmission provider's coordinated and regional planning process set forth in Attachment K of its OATTs. Thus, all new transmission service agreements executed after the effective date of Attachment K will be subject to the five year/one year right of first refusal rule. The Commission proposes that transmission service agreements subject to a right of first refusal entered into prior to the effective date of revised section 2.2, unless terminated, will become subject to the five year/one year right of first refusal rule on the first rollover date after the effective date of revised section 2.2.

358. Our existing policy allows the transmission provider to limit a transmission customer's right of first refusal by reserving capacity to accommodate reasonably forecasted and verifiable native and network load growth at the time the initial service agreement is executed. Many transmission providers argue that this right should be extended to allow the transmission provider to limit the right of first refusal each time the right of first refusal is exercised, not only at the time the initial service agreement is executed. We believe that our proposal to extend the term of the right of first refusal from one to five years should address, in many respects, the concern of transmission providers that the existing right of first refusal is unfair to native load customers. Under this proposal, a right of first refusal will no longer be granted to users of the grid on an annual basis, but rather only to those making longer-term commitments to the grid, as do native load customers. In addition, while we expect a transmission provider to be continually updating its forecast for native load growth and applying this updated projection to new requests for service, applying this to contracts at rollover may require an additional change to the right of first refusal process. Specifically, the transmission provider would have to compete for the capacity rather than reclaim it through its rights to reserve capacity for native load growth. We seek comment on whether this change would be appropriate. Further, while we have addressed requests to limit the right of first refusal on the basis of native load growth on a case-by-case basis, we recognize that this approach has not yet resulted in a clear and transparent method for demonstrating forecasted native load growth. Accordingly, we seek comment on whether there is a sufficiently clear, consistent, and transparent method that could be implemented on a generic basis to address the need for a transmission provider to demonstrate its forecast of native load growth and its effect on capacity reserved by right of first refusal customers.

359. Many transmission providers argue that our current right of first refusal policy is inconsistent with the native load protections contained in section 217(b) of the FPA. We disagree, but note that the reforms being proposed here should moot this argument. We are proposing to extend the minimum term of the right of first refusal to a period (five years) that is more consistent with the planning horizons of transmission providers. In addition, limiting the right of first refusal to agreements with terms of five years or more will ensure that the right of first refusal is used by customers with long-term obligations to purchase capacity rather than as a means for customers with shorter-term transactions to use capacity for non-load-serving-entity transactions.[337] This is consistent with FPA section 217(b)(4), which states that the Commission shall exercise its authority ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities.'' Our proposal also is consistent with FPA section 217(b)(2) because it continues to allow the transmission provider to limit the right of first refusal to accommodate reasonably forecasted and verifiable native load growth.

360. Under the proposed rule, transmission providers still will be required to plan their systems with the expectation that a transmission

[337] This is consistent with the approach suggested by TAPS, which argues that the current one-year minimum contract term allows significant capacity on constrained interfaces to be tied up in relatively short-term deals simply designed to hold the firm reservation as a path for non-firm economy purchases and to block competitors' firm access (*e.g.*, inexpensive, one-year ''paper capacity'' deals). TAPS also argues that any restriction on the availability and flexibility of rollover rights be contingent on an expansion of the transmission grid so that transmission customers have reasonable access to competitive supplies. We agree that expansion of the grid is critical and accordingly have proposed to require coordinated transmission planning on both a local and regional level to ensure that transmission customers' needs are treated comparably to those of the transmission provider. This enhanced transmission planning, combined with other reforms proposed in this NOPR (*e.g.*, improvements to the calculation of ATC), should mitigate TAPS's concerns by improving the ability to access competitive supplies.

customer with a long-term transmission agreement subject to a right of first refusal will exercise its rollover right at the end of its term. We believe it is important to reiterate the obligation on transmission providers to maintain ATC for existing transmission customers with rollover rights and our expectation that transmission providers will include all customers with rollover rights in their long-term planning.[338] We understand that some existing reliability procedures or practices may encourage transmission providers to exclude certain transmission service contracts from their base-case models, even if those contracts contain a rollover right. This is inconsistent with Commission policy and undermines the purpose of the rollover right, which is to facilitate system planning and reliability.

4. Modification of Receipt or Delivery Points

361. Section 22 of the *pro forma* OATT provides that a transmission customer taking firm point-to-point service may modify its receipt and delivery points on either a non-firm or a firm basis. Section 22.1 (Modifications on a Non-Firm Basis) provides that, subject to certain conditions, a firm point-to-point customer may request transmission service on a non-firm basis over receipt and delivery points other than those specified in its service agreement (known as secondary receipt and delivery points) in amounts not to exceed its firm capacity reservation, without incurring an additional non-firm point-to-point service charge or executing a new service agreement. Section 22.2 (Modifications on a Firm Basis) provides that any request to modify receipt and delivery points on a firm basis shall be treated as a new request for service in accordance with section 17 of the *pro forma* OATT (Procedures for Arranging Firm Point-to-Point Transmission Service), except that the transmission customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing service agreement. While such new request is pending, the transmission customer retains its priority for service at the existing firm receipt and delivery points specified in its service agreement.

362. In the NOI, the Commission asked whether transmission customers have experienced undue discrimination in attempting to redirect to new receipt and delivery points pursuant to section 22.2 and whether any reforms were needed. The Commission did not specifically ask about section 22.1, but some commenters nevertheless addressed this section. Most commenters, however, did not distinguish whether they were concerned with firm or non-firm redirects and instead addressed redirects generally.

Comments

363. APPA notes that many of its members have experienced difficulties in changing receipt points, especially when such requests involve new sources of supply. In many cases, APPA asserts that transmission providers require major upgrades before they will grant a redirect to new points. The Public Power Council points out that redirecting to new points depends on ATC, and, therefore, the ability to make changes would be improved by better public knowledge of ATC at those points in all timeframes and by more information about ATC calculation methodologies. EPSA asserts that difficulty in redirecting to new points inhibits the ability to reassign capacity. Williams complains about delays by transmission providers in answering requests for redirects and urges the Commission to enforce OATT procedures and to consider a ''fast-track'' process for reviewing requests to redirect.

364. Bonneville and EEI believe that any discrimination may be an unintentional result of a lack of clarity in the *pro forma* OATT, and are joined by MidAmerican, Progress Energy, and PNM–TNMP in calling for a number of clarifications. MidAmerican believes that these clarifications will provide flexibility to transmission customers and will enhance the ability to reassign transmission service to customers desiring different points of receipt or delivery.

365. Southern and Ameren assert that because customers often make redirect requests at the last minute, there is often not enough time for the market to respond to capacity made available on an abandoned path. Southern also highlights the administrative burdens and complexity (particularly for reliability) of processing short-term changes in service and suggests that the Commission consider measures to encourage transmission customers to provide greater certainty as to the expected paths along which they will schedule service and to do so in a more timely manner. Southern, along with Bonneville, also urges the Commission to clarify rollover rights when service is redirected to new points. In general, however, Southern believes that the Commission's current redirect policies are reasonable and practical.

366. A number of commenters focus on other related transmission issues, such as the flexibility afforded network service versus point-to-point service or other network-service-related issues;[339] the lack of flexibility with point-to-point service generally;[340] or issues associated with the interconnection of network load at new delivery points.[341]

Discussion

367. The Commission believes that it has already addressed many of the concerns raised by commenters with regard to reform of section 22 of the *pro forma* OATT in Docket No. RM05–5–000.[342] In Order No. 676, the Commission adopted the ''Standards for Business Practices and Communication Protocols for Public Utilities'' developed by the NAESB's Wholesale Electric Quadrant (WEQ).[343] Order No. 676 incorporates the aforementioned standards by reference into the Commission's regulations; requires public utilities to implement the standards by July 1, 2006; and requires public utilities to file revisions to their OATTs to include these standards.[344] The WEQ Standards recently adopted by the Commission include a number of standards addressing requirements for dealing with redirects on both a firm and non-firm basis.[345] In fact, all of the WEQ Standards dealing with redirects were adopted by the Commission in Order No. 676, except for WEQ Standard 001–9.7, which addresses the impact of a firm redirect on a long-term firm transmission customer's rollover rights under section 2.2 of the *pro forma* OATT. The Commission directed the WEQ to reconsider WEQ Standard 001–9.7 and to adopt a revised standard consistent with the Commission's

[338] *See, e.g., Southern Company Services, Inc.*, 104 FERC ¶ 61,140 at P 26–27 (2003).

[339] *E.g.,* Alberta Intervenors, Calpine, and TAPS.

[340] *E.g.,* Occidental.

[341] *E.g.,* NRECA and TDU Systems.

[342] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676, 71 FR 26199 (May 4, 2006), FERC Stats. & Regs. ¶ 31,216 (2006).

[343] The WEQ was established by NAESB in response to a Commission order requesting the wholesale electric power industry to develop business practice standards and communication protocols by establishing a single consensus, industry-wide standards organization for the wholesale electric industry. *See id.* at P 3–4.

[344] The standards will hereinafter be referred to as the WEQ Standards. The Commission proposes to add a reference to the WEQ standards in section 4 of the *pro forma* OATT, which identifies the Commission's regulations containing the terms and conditions relevant to the OASIS and standards of conduct.

[345] The requirements for dealing with redirects on a firm basis are found at WEQ Standard 001–9, *et seq.*, and the requirements for dealing with redirects on a non-firm basis are found at 001–10, *et seq.*

policies.[346] The Commission also offered guidance to assist the WEQ in developing a standard that is consistent with Commission policy.[347]

368. As noted above, we believe that a number of concerns raised by commenters are addressed by the WEQ Standards. For example, we believe that the request of commenters for clarification that redirect service may be requested for only a portion of the original quantity of service is addressed for firm and non-firm service by WEQ Standards 001–9.2 and 001–10.2, respectively, which provide that the transmission customer ''shall be allowed to request a Redirect on a [Firm/Non-Firm] basis for a portion or all of the Capacity Available to Redirect.'' Likewise, the request of commenters for clarification that it is not necessary for a customer to redirect its service for the entire remaining term of service is addressed for firm and non-firm service by WEQ Standards 001–9.3 and 001–10.3, respectively, which provide that the transmission customer ''shall be allowed to request a Redirect on a [Firm/Non-Firm] basis for a portion or all of the time period of the Parent Reservation.'' While we believe that many concerns expressed by commenters with regard to redirects in this proceeding have been addressed by Order No. 676, we request that each commenter reconsider its concerns in this area with the benefit of Order No. 676's adoption of the WEQ Standards, and inform us if additional concerns remain. The Commission notes that several of the most active commenters addressing redirects in this proceeding also were commenters in Docket No. RM05–5–000 and therefore should be familiar with whether a particular WEQ Standard addresses the issues raised in the comments submitted in this proceeding.[348]

369. The Commission anticipates that a number of other concerns, while perhaps not yet addressed (or addressed fully) by a WEQ Standard, are nevertheless the types of issues appropriate for the WEQ process. The Commission therefore proposes that each commenter that continues to believe additional reform is necessary in this area also evaluate whether its concerns would more appropriately be addressed by the WEQ as it considers its next version of its standards.[349] Specifically, as noted above, the WEQ is in the process of reevaluating WEQ Standard 001–9.7, dealing with redirects and rollovers, so that it is consistent with the Commission's guidance given in Order No. 676. The Commission requests comment on whether the WEQ process, along with the guidance provided by the Commission in Order No. 676, is sufficient to address the concerns of commenters that seek clarification on the interplay between redirects and rollovers.

370. The Commission understands, however, that there are also more fundamental concerns with regard to section 22 that were raised in the NOI. Many comments reflect concerns about the inability of transmission customers to effectively redirect their transmission service to new receipt and delivery points in order to accommodate a new transaction, the reassignment of capacity, or the designation of a new supply source. Generally, these commenters argue that their ability to redirect to new points is stymied by a lack of ATC at the new points or the need for major upgrades at the new points; or that the transmission provider takes too long to process its redirect request. Transmission providers, on the other hand, complain of the administrative burdens and complexity (particularly with regard to reliability) of processing transmission customers' short-term changes in service, and also assert that there is often not enough time for the market to respond to capacity made available on customers' original paths.

371. The ability to redirect to new points is a function of whether there is ATC at the new points. The Commission believes that its proposed reforms requiring coordinated transmission planning between transmission providers and their customers, as well as regional transmission planning open to all stakeholders, will lead to a more rationally planned transmission system that will result in fewer transmission constraints and more ATC available to accommodate requests to redirect to new points.[350] Additionally, the Commission's proposed reforms regarding the calculation of ATC and increased transparency over the process will engender increased confidence among transmission customers in their transmission providers' ATC postings.[351] In short, transmission customers will have more accurate and complete ATC information to utilize in evaluating their redirect options. Moreover, through increased transparency, transmission customers will have the information they need to question a transmission provider's denial of a request to redirect. Thus, we believe that our reforms in the area of transmission planning and ATC calculation should go a long way toward addressing transmission customer concerns in this area. Should commenters believe that our proposed reforms in this area will not address their concerns effectively, or that there is a better way of addressing them, we encourage them to submit a specific proposal, along with proposed revised *pro forma* OATT language.

372. We believe that redirects should be as customer-friendly as possible. Other *pro forma* OATT reforms proposed in this rulemaking should improve the ability to redirect transmission service to new points pursuant to section 22. For example, the modifications to firm point-to-point service discussed above will be applicable to a request to redirect on a firm basis, as such requests are treated as a new request for service under *pro forma* OATT section 22.2. In addition, reforms related to the acquisition of service discussed below (*e.g.*, with regard to making and processing requests for service, queuing, and reservation priority) should, among other things, help to address transmission customer concerns that transmission providers are too slow in processing redirect requests. These reforms also should help to address transmission provider concerns that customers do not respond completely and in a timely manner and that there is insufficient time to re-market capacity on the original paths.

5. Acquisition of Transmission Service

a. Processing of Service Requests

373. The *pro forma* OATT includes requirements that transmission providers process requests for transmission service in a timely fashion. Section 17.5 (Response to a Completed Application) and section 18.4 (Determination of Available Transmission Capability) of the *pro forma* OATT provide that following the receipt of a completed application for service, the transmission provider must respond to transmission customer requests for determinations of the availability of firm and non-firm

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[346] Order No. 676 at P 52.

[347] *Id.* at P 53–61.

[348] For example, Bonneville, EEI, NRECA, and Southern each commented in Docket No. RM05–5–000.

[349] The Commission notes in this regard that the WEQ's procedures ensure that all industry members can have input into the development of a business practice standard, whether or not they are members of NAESB, and each standard it adopts is supported by a consensus of the five industry segments: Transmission, generation, marketers/brokers, distribution/load-serving entities, and end-users. *See* Order No. 676 at P 5 & n.5.

[350] *Supra* Part V.B.

[351] *Supra* Part V.A.

transmission capacity on a timely basis. The transmission provider must make the determination as soon as reasonably practicable after receipt but no later than certain specified time periods (or such time periods generally accepted in the region). Section 19 (Additional Study Procedures for Firm Point-to-Point Transmission Service Requests) of the *pro forma* OATT provides deadlines that transmission providers must adhere to in issuing system impact study agreements and facilities studies agreements and that transmission customers must abide by in responding to these study agreements. Section 19 requires transmission providers to use due diligence to complete system impact studies and facilities studies within 60 days. Section 32 of the *pro forma* OATT (Additional Study Procedures for Network Integration Transmission Service Requests) contains similar due diligence deadlines for completing system impact studies and facilities studies associated with requests for network service.

374. In the NOI, the Commission sought comment on problems transmission customers and transmission providers have experienced regarding the timely processing of requests for transmission service. In particular, the Commission sought comment regarding whether transmission customers have experienced delays by transmission providers in responding to requests for transmission service in general and, in particular, what problems commenters have experienced as transmission providers process the queue for requests for transmission service that cannot be immediately granted due to a lack of ATC. We also asked about the type of remedies the Commission should impose on public utility transmission providers for missing deadlines set forth in their OATTs. Another issue we sought comment on was whether commenters have identified blocking issues, such as where a customer submits multiple requests intending to proceed with a single request specifically to keep others out of the queue; and if so, whether allowing transmission providers to charge a processing fee would reduce the incentive to submit multiple self-competing requests. Finally, we sought comment on whether the Commission should require transmission providers to study transmission requests as a group.

Comments

375. A number of merchant generators articulated general concerns regarding the time it takes transmission providers to process requests for transmission service.[352] EPSA notes that timeliness in responding to transmission requests is a consistent problem. Constellation states that the untimely processing of requests for transmission service is a persistent problem under the OATT, particularly with respect to long-term point-to-point service, network service, and modification of network resource designations. Arkansas Cities adds that, under the current OATT, utilities' lenient application of time periods needed for the system impact study process and facilities study process cause transmission customers to endure significant amounts of time to obtain confirmed firm delivery service at a reasonable cost.

376. A number of commenters suggest that transmission providers should inform the Commission when they miss the target deadlines for completing system impact studies and facilities studies and/or post performance statistics on their OASIS sites that detail the time it takes them to process system impact studies and facilities studies.[353] EPSA states that it strongly believes that the new OATT should require the transmission provider to notify the Commission when it is not able to meet deadlines. TDU Systems suggests that one way to address the difficulty of determining acceptable delays is to require transmission providers to post statistics on their OASIS sites providing information as to the length of time it might take to process requests for transmission service. Cinergy proposes that adopting specific reporting metrics that require transmission providers to report certain statistics regarding their performance could result in an improved quality of service.

377. A number of merchant generators propose that the Commission assess operational penalties on transmission providers that fail to meet the study deadlines detailed in the *pro forma* OATT.[354] LG&E recommends that the Commission consistently enforce the established deadlines through penalties or other remedies unless good cause for failure to comply can be shown, so as to promote nondiscriminatory adherence to established deadlines. Powerex suggests that the Commission: (a) Identify a threshold percentage rate of acceptable compliance with response timelines, (b) require transmission providers to monitor and post their own rates of compliance with Commission-required timelines on a path-specific basis, as well as the reasons for delays, (c) require transmission providers whose rate of compliance on a particular path falls below the Commission's threshold to file a compliance report with the Commission identifying the problem(s) and corrective measures that will be undertaken (including a timeline for implementation of the corrective measures), and (d) use a progressive penalty system that begins with reporting and auditing requirements for non-compliant transmission providers and then moves toward monetary penalties in cases where a transmission provider exhibits a pattern of uncorrected noncompliance, as well as in any case where actual bad faith, discrimination or preferential treatment has occurred.

378. A number of transmission providers state that transmission service request processing is slowed by excessive requests for transmission service from the same transmission customer with essentially the same service attributes (*e.g.*, point of receipt, point of delivery, start time, end time, firmness).[355] A number of other commenters also argue that some transmission customers submit multiple requests for transmission service with no intent to confirm most of the requests if and when the requests are accepted.[356] MidAmerican states that it is aware of cases where customers have submitted multiple requests for service associated with a new generator where the location of the new generator is not known but queue priority is being sought by the transmission customer. MidAmerican adds that the submission of such multiple requests for service affects the processing of other lower queued transmission requests. South Carolina E&G states that there are instances when a transmission customer submits multiple requests intending to proceed with a single request, seemingly with the purpose of keeping others out of the queue. AWEA states that transmission queues are frequently jammed with many projects holding each other up. AWEA asserts that there often are ''zombie'' projects blocking the queue, without a power purchase agreement or other indication that they are serious projects. Suez Energy NA responds that there are blocking issues when a transmission customer submits multiple requests for transmission

[352] *E.g.,* Constellation, EPSA, Powerex, and Williams.

[353] *E.g.,* Cinergy, Constellation, EPSA, MidAmerican, Powerex, and TDU Systems.

[354] *E.g.,* EPSA, Powerex, and Williams.

[355] *E.g.,* MidAmerican, Progress Energy, South Carolina E&G, and Southern.

[356] *E.g.,* Alberta Intervenors, AWEA, Public Power Council, and Suez Energy NA.

service but intends to proceed with a single request.

379. Several federal power agencies suggest that charging a fee on transmission service requests could provide the right incentive to transmission customers to limit requests for transmission service to only those requests they expect to confirm.[357] Several other commenters suggest a similar fee.[358] Bonneville supports the imposition of a processing fee for multiple requests to provide a disincentive to blocking behavior. Bonneville suggests that the fee should provide a disincentive for making multiple, ''self-competing'' requests. Bonneville suggests that, at a minimum, requests with the same point of receipt, point of delivery, source, sink, and time-frame should be considered ''self-competing.'' In addition, Bonneville contends that transmission providers should be allowed to define parameters to identify additional instances of ''self-competing'' requests on their systems. South Carolina E&G argues that there is merit to the concept of charging a processing fee that would increase with the duration of the requested service, to reduce the incentive to submit multiple self-competing requests.

380. The majority of commenters were in favor of allowing, but not requiring, transmission providers to study requests for transmission service as a group, also known as clustering requests for transmission service.[359] APPA and Bonneville suggest amending the *pro forma* OATT so that all requests received during a set time period are studied together. EEI argues that the Commission should not require the studying of transmission requests as a group, though transmission providers should continue to have the discretion to cluster transmission requests when it is efficient to do so. EPSA states that clustering should not be required, but may be considered as a customer option as part of a comprehensive planning process.

381. Bonneville suggests that the Commission adopt two NAESB proposed business standards designed to reduce the number of self-competing requests. In particular, Bonneville believes the Commission should adopt NAESB's proposed queue hoarding business practice and queue flooding business practice.

[357] *E.g.,* Bonneville and TVA.

[358] *E.g.,* Alberta Intervenors, Snohomish, and South Carolina E&G.

[359] *E.g.,* EEI, EPSA, Nevada Companies, PacifiCorp, PNM–TNMP, Powerex, and Southern.

Discussion

382. We agree with commenters who argue that requiring transmission providers to report the length of time they take to complete studies pursuant to sections 19 and 32 of the *pro forma* OATT would increase transparency and improve the ability of transmission customers and the Commission to detect undue discrimination. Therefore, we propose to require transmission providers to post on their OASIS sites metrics that track their performance in processing system impact studies and facilities studies associated with requests for transmission service. Transmission providers will be required to post the performance metrics, outlined below, for each calendar quarter. Transmission providers should begin tracking their performance upon the effective date of the final rule in this proceeding and keep the quarterly performance metrics posted on their OASIS sites for three calendar years. The transmission provider will be required to post the quarterly performance metrics within 15 days of the end of the quarter. The performance metrics outlined below should be calculated separately for affiliates' and non-affiliates' requests for short-term and long-term transmission service. A transmission provider also will be required to post performance metrics for studies that it conducts for RTOs.

383. We propose to require transmission providers to post the following set of performance metrics on a quarterly basis:

- Process Time from Initial Service Request to Offer of System Impact Study Agreement pursuant to Sections 17.5, 19.1 and 32.1 of the *pro forma* OATT
  - Number of new System Impact Study Agreements delivered to Transmission Customers
  - Number of new System Impact Study Agreements delivered to the Transmission Customer more than 30 days after the Transmission Customer submitted its request
  - Average time (days) from request submittal to change in request status
  - Average time (days) from request submittal to delivery of System Impact Study Agreement
  - Number of new System Impact Study Agreements executed
- System Impact Study Processing Time pursuant to Sections 19.3 and 32.3 of the *pro forma* OATT
  - Number of System Impact Studies completed
  - Number of System Impact Studies completed more than 60 days after receipt of executed System Impact Study Agreement
  - Average time (days) from receipt of executed System Impact Study Agreement to date when completed System Impact Study made available to the Transmission Customer
  - Average cost of System Impact Studies completed during the period
- Service Requests Withdrawn from System Impact Study Queue
  - Number of requests withdrawn from the System Impact Study queue
  - Number of System Impact Studies withdrawn more than 60 days after receipt of executed System Impact Study Agreement
  - Average time (days) from receipt of executed System Impact Study Agreement to date when request was withdrawn from the System Impact Study queue
- Process Time from Completed System Impact Study to Offer of Facilities Study pursuant to Sections 19.4 and 32.4 of the *pro forma* OATT
  - Number of new Facilities Study Agreements delivered to Transmission Customers
  - Number of new Facilities Study Agreements delivered to Transmission Customers more than 30 days after the completion of the System Impact Study
  - Average time (days) from completion of System Impact Study to delivery of Facilities Study Agreement
  - Number of new Facilities Study Agreements executed
- Facilities Study Processing Time pursuant to Sections 19.4 and 32.4
  - Number of Facilities Studies completed
  - Number of Facilities Studies completed more than 60 days after receipt of executed Facilities Study Agreement
  - Average time (days) from receipt of executed Facilities Study Agreement to date when completed Facilities Study made available to the Transmission Customer
  - Average cost of Facilities Studies completed during the period
  - Average cost of recommended upgrades for Facilities Studies completed during the period
- Service Requests Withdrawn from Facilities Study Queue
  - Number of requests withdrawn from the Facilities Study queue
  - Number of Facilities Studies withdrawn more than 60 days after receipt of executed Facilities Study Agreement
  - Average time (days) from receipt of executed Facilities Study Agreement to date when request was withdrawn from the Facilities Study queue

384. We also propose to impose operational penalties when transmission providers routinely fail to meet the 60-

day due diligence deadlines prescribed in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. We propose to require a transmission provider to file a notice with the Commission in the event the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT for two consecutive quarters. For the purposes of calculating this notification trigger, the transmission provider should aggregate all system impact studies and facilities studies that it completes during the quarter for non-affiliates.[360] The transmission provider may explain in its notification filing that it believes there are extenuating circumstances that prevented it from meeting the deadlines in the *pro forma* OATT. The transmission provider then will be subject to an operational penalty if the transmission provider continues to be out of compliance with the deadlines prescribed in the *pro forma* OATT for each of the two quarters following its notification filing. The transmission provider will be deemed to be out of compliance if it completes 10 percent or more of non-affiliates' system impact studies and facilities studies outside of the deadlines prescribed in the *pro forma* OATT. The operational penalty will be assessed on a quarterly basis, starting with the quarter following the notification filing and continuing until the transmission provider completes at least 90 percent of all studies within 60 days after the study agreement has been executed. For any system impact study or facilities study completed during that quarter and more than 60 days after the study agreement was executed, the penalty will equal $500 for each day the transmission provider takes to complete the study beyond 60 days. For any system impact study or facilities study that is still pending at the end of the quarter and that has been in the study queue for more than 60 days, the penalty will equal $500 for each day the study has been in the study queue beyond 60 days. Because of their independence, we do not believe that RTOs have an incentive to neglect their obligation to process applications for service in a timely fashion. As a result, we propose that RTOs will not be subject to this penalty regime.

385. In addition to the operational penalty described above, we propose to require transmission providers to post on their OASIS sites additional performance metrics after making a notification filing. Transmission providers will have to post these performance metrics until they process at least 90 percent of all system impact and facilities studies within 60 days after the study agreement has been executed. Starting the quarter following a notification filing, the transmission provider will be required to post: (1) The average, across completed system impact studies, of the employee-hours expended per completed system impact study; (2) the average, across completed facilities studies, of employee-hours expended per completed facilities study, (3) the number of employees devoted to processing system impact studies, and (4) the number of employees devoted to processing facilities studies. These additional performance metrics should be calculated separately for affiliates' and non-affiliates' requests for transmission service and for short-term and long-term transmission service.

386. In addition to the operational penalties described above, we may order other remedial actions, consistent with the Enforcement Policy Statement. Any other remedial action will be determined on a case-by-case basis. The transmission provider will pay the operational penalty described above, consistent with the proposed rule discussed in Part V.C.4.b. The transmission provider cannot recover for ratemaking purposes any operational penalty it pays for failing to process transmission service studies on a timely basis.

387. With respect to the problem of multiple, self-competing transmission service requests, we seek comment on a fee structure that could provide a disincentive for transmission customers to submit such duplicative requests without penalizing transmission customers that have legitimate requests for transmission service. We seek detailed recommendations, including any proposed tariff language, regarding the standards we would use to identify requests that would be subject to a fee. We also seek recommendations on the level of the fee that balances our policy goals to discourage requests for transmission service that the transmission customer does not intend to confirm while not discouraging legitimate requests for transmission service. Finally, we seek comment regarding the circumstances, if any, under which the processing fee would be refunded to or credited to the transmission customer.

388. In Order No. 2003, we encouraged transmission providers to study interconnection requests in clusters.[361] We likewise encourage transmission providers to study requests for transmission service in clusters, though we will not require transmission providers to cluster requests for transmission service for study purposes.[362] As with interconnection requests, studying requests for transmission service in clusters allows the transmission provider to consider all requested uses of the transmission system at one time. We seek comment regarding whether transmission providers should be required to study requests for transmission service in a group if the transmission provider fails to complete studies on a timely basis; and, if so, we seek comment on the circumstances that should trigger such a requirement and the appropriate method of implementing the requirement. We further seek comment regarding whether transmission providers should be required to study requests for transmission service in a group if all the transmission customers in the group agree to cluster their requests. We also seek comment regarding how to select the requests that belong to a cluster so that transmission customers cannot ''cherry-pick'' clusters to avoid transmission system upgrade costs.

389. In Order No. 676, we incorporated by reference a number of NAESB business practices, including the business standards on queue hoarding and queue flooding.[363] NAESB's queue hoarding business practice allows transmission providers to deny a transmission customer's identical requests for transmission service if the customer elects not to accept an initial offer of identical, or substantially identical, transmission service. NAESB's queue flooding business practice allows a transmission provider to invalidate the submission of additional identical requests for transmission service when the sum of all previously submitted identical requests for transmission service equals or exceeds the total transfer capability on the requested path for any time period during the duration of the requests. We would consider the decision by a transmission provider to

[360] For instance, if the transmission provider completes 4 non-affiliates' system impact studies during the quarter with 2 completed more than 60 days after the system impact study agreement was executed and completes 2 non-affiliates' facilities studies during the quarter with none completed more than 60 days after the facilities study agreement was executed, then the transmission provider will be deemed to have completed 2 out of 6 (33 percent) studies outside of the deadlines in the *pro forma* OATT.

[361] Order No. 2003 at P 155.

[362] We note that we previously have allowed transmission providers to study requests for transmission service in a group. *See, e.g.*, *Southwest Power Pool, Inc.*, 110 FERC ¶ 61,028 at P 16 (2005).

[363] *See* Order No. 676 at P 19.

deny service under the queue hoarding business practice and the decision to invalidate requests under the queue flooding business practice to be an act of discretion under 18 CFR 37.6(g)(4) (2005). As a result, the transmission provider is to log the actions it takes under the queue flooding and queue hoarding business practices.

b. Queue Processing Business Practices

390. The set of uniform business practices adopted in Order No. 676 relating to transmission service price negotiation and on improving interaction between transmission customers and transmission providers over OASIS nodes. These business practices include standards for the time limit within which (1) transmission providers must respond to requests for transmission service, (2) transmission customers must confirm service, and (3) transmission providers must respond to a rebid from a transmission customer.[364] These business practices also include negotiation priority rules, including the terms under which a request can be pre-empted and under which a request has the right-of-first-refusal.[365]

391. In the NOI, the Commission sought comment regarding whether there are provisions of the *pro forma* OATT that need to be reformed to better define the obligations of public utility transmission providers in responding to requests for transmission service.

Comments

392. Several commenters asked that the Commission require transmission providers to post standard business practices that describe how the transmission provider will process requests for transmission service.[366] MidAmerican suggests that transmission providers should be required to post on their OASIS sites a business practice documenting how they process their queues, requests outside the queue, and expected completion times. Calpine believes that the processing of requests for transmission service, and the deadlines associated with that process, should be standardized for all transmission service providers. For example, Calpine notes that Entergy's OASIS business practices state that Entergy will respond to fixed, hourly non-firm transmission service requests ''within 30 minutes of receiving the request for the requests received earlier than 1 hour before the service is to commence.'' By comparison, Calpine continues, SPP's tariff explains that hourly, non-firm transmission service requests for the next hour may be submitted no later than 20 minutes prior to the start of service.

Discussion

393. Order No. 676 contains many of the business practices we expect transmission providers to follow when they process requests for transmission service, including the issue Calpine raises in its comments about discrepancies between Entergy's and SPP's processes for requests for hourly non-firm transmission service. Calpine's comment addresses the deadline for transmission customers to submit requests for non-firm hourly point-to-point service and the deadline for transmission providers to respond to requests for non-firm hourly point-to-point service. Standard 001–4.13 in Order No. 676 indicates that transmission providers should use their best efforts to respond to requests for non-firm hourly point-to-point service that are submitted less than an hour prior to start and transmission providers should respond within 30 minutes to requests that are submitted more than an hour before start. In addition, in this NOPR we have provided additional clarity regarding the calculation of ATC and requirements for processing rollover requests. We also provide general guidance regarding which business practices should be filed as part of a transmission provider's OATT and which should be posted on OASIS. Given this additional clarity and the business practices already mandated by Order No. 676, we seek comment on whether commenters believe additional standardization of request queue processing is necessary. If so, we seek comment on the specific issues commenters believe are not clearly prescribed in Order No. 676 or this NOPR and which require additional mandatory queue processing business practices.

c. Reservation Priority

394. Section 13.2 of the *pro forma* OATT requires transmission providers to process requests for long-term firm point-to-point service on a first-come, first-served basis. In the NOI, we asked whether the first-come, first-served approach to reservation priorities has resulted in a fair and equitable means of allocating transmission capacity when the transmission system is oversubscribed. If not, we asked whether an alternative approach should be implemented.

Comments

395. Most transmission providers and federal power agencies respond that the first-come, first-served approach to allocating transmission service is the best alternative available.[367] Several merchant generators and public power entities concur that no better alternative exists.[368] Several commenters suggest that the first-come, first-served approach may provide an advantage to transmission customers who have the financial resources to purchase software and employ staff to continually monitor OASIS sites.[369] Santa Clara states that entities that have superior software and are able to consistently procure capacity to the exclusion of other market participants may have an unfair advantage.

396. For the short-term market, Bonneville contends, the first-come, first-served approach has two defects: (1) It advantages larger and better-financed transmission customers, which can continually monitor OASIS sites and submit requests electronically the moment new ATC is posted; and (2) it results in arbitrary awards of transfer capability when one customer's submission precedes a second customer's submission by mere seconds. Bonneville suggests that the Commission modify the first-come, first-served rule for awarding short-term firm point-to-point service capacity so that all requests submitted within a given time-frame are considered simultaneously submitted.

397. Several commenters propose some version of priority preference for requests for transmission service that are pre-confirmed.[370] Bonneville states that transmission customers flood the queue with unconfirmed requests to force competitors with higher queue positions to extend the length of their requests to retain their queue positions.

398. Bonneville suggests that the Commission consider reducing the time transmission customers have to confirm requests for short-term transmission service after the transmission provider has accepted a request for short-term transmission service. Bonneville states that a shorter time-frame would clear the short-term firm transmission market more quickly and make it more difficult for transmission customers to tie up scarce transfer capability.

[364] *Id.*, Standards 001–4.6 and 001–4.13.

[365] *Id.*, Standards 001–4.14 and 001–4.16.

[366] *E.g.*, Calpine, MidAmerican, and TDU Systems.

[367] *E.g.*, Ameren, EEI, Nevada Companies, TVA, and WAPA.

[368] *E.g.*, NRECA, Powerex, Public Power Council, Sempra, and TDU Systems.

[369] *E.g.*, Bonneville and Santa Clara.

[370] *E.g.*, Bonneville, Entergy, and South Carolina E&G.

399. Powerex suggests that the Commission clarify its reservation priority standards so that when transmission providers make use of discounts in short-term service, price (not to exceed the ceiling price) should be the third-level tie breaking mechanism, with higher-priced requests of equal duration having greater priority and requests earlier in the open access same-time information system having right of first refusal to match subsequent requests. Powerex states that in the presence of discounting, the open access transmission tariff allows a higher value service (firm) to be sold at a lower price than a lower value service (non-firm) even in the same operating horizon, because price based displacement only applies to short-term non-firm transmission services.

Discussion

400. In response to comments that transmission customers that have the financial resources to purchase software and employ staff to continually monitor OASIS sites have an unfair advantage under a first-come, first-served approach, we seek comment regarding whether any such advantage would be mitigated if all requests submitted within a 5-minute window, with duration as a tie breaker, were deemed to have been submitted simultaneously. We also seek comment on whether transmission customers could game a 5 minute equivalent priority standard to request transmission service only after another transmission customer has made a request. To the extent we adopt a 5 minute equivalent priority standard, we propose to allocate capacity on a pro rata basis, though we seek comment on other methods for allocating limited transmission capacity among equivalent priority requests of equal duration.

401. We also propose to change the priority rules to give priority to pre-confirmed requests. As a result, a pre-confirmed short-term request for firm transmission service would preempt any non-pre-confirmed short-term requests, regardless of duration. Similarly, a pre-confirmed request for long-term firm transmission service would preempt a request for long-term transmission service that is not pre-confirmed. We seek comment on whether this change to the reservation priority rules will alleviate concerns commenters have expressed regarding the flooding or jamming of the transmission queue by transmission customers who submit multiple requests for transmission service.

402. We propose to add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service. Price would serve as a tie-breaker after pre-confirmation for those requests that are not yet confirmed. As a result, a pre-confirmed request for short-term firm point-to-point service would preempt another pre-confirmed request for short-term firm point-to-point service that has an earlier queue time, and an equal or shorter duration but a lower offer price. However, a request for short-term firm point-to-point service that is not pre-confirmed would not preempt a pre-confirmed request for short-term firm point-to-point service that has an earlier queue time, and an equal or shorter duration but a lower offer price.

6. Designation of Network Resources

a. Qualification as a Network Resource

403. Taken together, the following sections of the *pro forma* OATT describe the resources a network customer can appropriately designate as a network resource. Section 30.1 of the *pro forma* OATT describes network resources as all generation owned or purchased by the network customer designated to serve network load under the tariff. Section 30.1 also indicates that network resources may not include resources that are committed for sale to non-designated third-party load or otherwise cannot be called upon to meet the network customer's network load on a noninterruptible basis. Pursuant to section 30.7 of the *pro forma* OATT, the network customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a network resource. Alternatively, the network customer may establish that execution of a contract is contingent upon the availability of network service. Section 29.2 requires the network customer to provide the following information about a power purchase agreement that is to serve as a new designated network resource: source of supply, control area location, transmission arrangements and delivery point(s) to the transmission provider's transmission system.

404. The Commission has issued a number of orders that clarify which resources meet the criteria set out in sections 30.1 and 30.7 of the *pro forma* OATT. In *MSCG,* the Commission stated that network resources must be generating resources owned by the network customer or purchases of noninterruptible power under executed contracts that require the network customer to pay for the purchase.[371] In *WPPI,* the Commission found that a network customer can designate as a network resource a system purchase that is not backed by a specific generator.[372] The Commission found that Wisconsin Public Service Corporation (WPS) had appropriately designated a power purchase as a network resource, even though the power purchase agreement did not require WPS to take energy around the clock and allowed WPS to convert its energy purchase to a discounted product that could be interrupted.[373] In addition, the Commission stated that because the *pro forma* OATT requires a power purchase to be noninterruptible, third-party transmission arrangements to deliver the resource to the network have to be noninterruptible as well.[374] In *Illinois Power,* the Commission found that a firm purchase need not be backed by a capacity purchase to qualify as a network resource.[375]

405. In the NOI, the Commission sought comment regarding whether network resources consisting of firm contracts that do not specify generation sources until the energy is scheduled (so-called ''seller's choice contracts'') are a problem. The Commission also sought comment on the specific difficulties entities have experienced with designation of network resources and asked what reforms are needed to the designations provision in the *pro forma* OATT.

Comments

406. A number of commenters indicate that firm contracts that do not specify generation sources are acceptable network resources as long as the network customer specifies enough information for the transmission provider to identify how the contract power will enter its control area.[376] Bonneville suggests that the customer should be required to identify the point(s) of receipt on the transmission provider's system whenever it designates a network resource. EEI states that the designation of seller's choice contracts as network resources is only problematic if the seller's choice contract permits the seller to choose the

[371] *Morgan Stanley Capital Group* v. *Illinois Power Co.*, 83 FERC ¶ 61,204 at 61,911–12 (1998), *order on reh'g*, 93 FERC ¶ 61,081 (2000) (*MSCG*).

[372] *Wisconsin Public Power Inc.* v. *Wisconsin Public Service Corp.*, 84 FERC ¶ 61,120 at 61,650–51 (1998) (*WPPI*).

[373] *Id.*

[374] *Id.* at 61,660.

[375] *Illinois Power Co.*, 102 FERC ¶ 61,257 at P 14 (2003), *reh'g denied*, 108 FERC ¶ 61,175 (2004) (*Illinois Power*).

[376] *E.g.,* Bonneville, EEI, Nevada Companies, Public Power Council, and TVA.

flowgate path over which the energy will be delivered. EEI further explains that no issue is present if the seller is limited to a single path or flowgate. On the other hand, PNM–TNMP argues that allowing seller's choice contracts to be considered network resources significantly complicates transmission planning, as virtually none of the information required by section 29.2 of the OATT can be provided.

407. Several commenters cited specific difficulties with or suggested specific modifications to the network designation provisions of the tariff. APPA indicated that under the liquidated damages provisions in the EEI contract, it is the buyer's responsibility to go out into the market to purchase replacement supplies (cover), and the seller then pays the buyer the difference between the contract price and the cover price. APPA states that these provisions are not consistent with the concept of having to specify generation resources or contracts as network resources, since the actual source and supplier of generation may well change at a time when both wholesale power supplies and transmission capacity are at a premium. Ameren suggests that the Commission clarify that liquidated damages products cannot be designated network resources. Ameren states that a liquidated damages contract allows a supplier to walk away from a deal if it can obtain a price elsewhere high enough to offset the liquidated damages provisions. Ameren argues that liquidated damages contracts are financial instruments that produce no electricity. MidAmerican also contends that provisions for designating liquidated damages contracts as network resources should be eliminated. Southwestern urges the Commission to reform the OATT to make it clear that a firm purchased power contract with liquidated damages should be eligible to be considered a designated network resource.

Discussion

408. We propose to maintain our current policy regarding the power purchase agreements that network customers may designate as network resources. In particular, a network customer will continue to be able to designate resources from system purchases not linked to a specific generating unit, provided the purchase power agreement is not interruptible for economic reasons, does not allow the seller to fail to perform under the contract for economic reasons, and the executed contract requires the network customer to pay for the purchase. In addition, third party transmission arrangements to deliver the purchase to the network have to be noninterruptible as well.

409. In response to comments that seller's choice contracts are problematic because the network customer can provide limited, if any, information required by section 29.2 of the *pro forma* OATT, we reiterate that a request to designate a new network resource must include the information specified in section 29.2(v), including the source of supply, control area location, transmission arrangements, and delivery point(s) to the transmission provider's transmission system. When a network customer is designating a system purchase as a new network resource, the source information required in section 29.2(v) should identify that the resource is a system purchase and should identify the control area from which the power will originate. A power purchase agreement that is structured so that a network customer cannot specify all of the information required by section 29.2(v) cannot be designated as a network resource.

410. In response to suggestions that liquidated damages products should not be designated network resources because they are interruptible for economic reasons, we clarify that network customers may not designate as network resources those power purchase agreements that give the seller a contractual right to compensate the buyer instead of delivering power even if the seller is able to deliver power. For instance, a network customer may not designate as a network resource a purchase agreement that allows the seller to interrupt service for reasons other than reliability, but allows the buyer to force delivery at a higher price. In addition, a network customer may not designate as a network resource a purchase agreement that requires a seller to pay the buyer's cost of replacement power when the seller chooses not to deliver energy for economic reasons.

b. Documentation for Network Resources

411. Section 30.2 of the *pro forma* OATT stipulates that a network customer request the designation of a new network resource by a request for modification of service pursuant to an application under section 29 of the *pro forma* OATT, and section 29.2 stipulates that the network customer must provide specified information about its designated network resources. The Commission found in *WPPI* that transmission customers may need to document compliance with specific requirements for obtaining tariff service, possibly including contractual terms.[377] The Commission went on to state that it expected a transmission provider's merchant function to police its own compliance with tariff obligations.[378]

Comments

412. LG&E suggests that the *pro forma* OATT require the transmission provider to have a process to verify that each load-serving entity has a contractual right to the resources they are designating. LG&E argues this would help eliminate concerns over double booking of resources by two parties. EPSA states that transmission providers have attempted to require customers to demonstrate that they have obtained contracts covering an annual period, rather than allowing customers to provide reasonable advance notice for each contract during the service period. EPSA asks the Commission to prohibit this practice.

Discussion

413. We clarify that transmission providers are not responsible for verifying that the generating units and power purchase agreements network customers designate as network resources satisfy the requirements in sections 30.1 and 30.7 of the *pro forma* OATT. While transmission providers are responsible for verifying that the network customer has provided all the information section 29.2 requires the network customer to provide, the transmission provider is not responsible for obtaining contractual terms to verify requirements in sections 30.1 and 30.7 of the *pro forma* OATT. The transmission provider continues to have the responsibility to verify that third-party transmission arrangements to deliver the purchase to the transmission provider's system are firm.

414. We propose to require the transmission provider's merchant function as well as network customers to include a statement with each application to designate a new network resource that attests that: (1) The transmission customer owns or has committed to purchase the new designated network resource, and (2) the new designated network resource comports with the requirements for designated network resources. The network customer should include this attestation in the customer's comment section of the request when it confirms the request. Similarly, we propose that all entities that submit an application for network service be required to

[377] *WPPI* at 61,660.

[378] *Id.*

include a statement with the application for service that attests that, for each network resource identified in the application for service: (1) The transmission customer owns or has committed to purchase the designated network resource, and (2) the designated network resource comports with the requirements for designated network resources.

415. We propose that if the network customer does not include an attestation when it confirms its request, the transmission provider will notify the network customer within 15 days of confirmation that its request is deficient. Wherever possible, the transmission provider will attempt to remedy deficiencies in the request through informal communications with the network customer. If such efforts are unsuccessful, the transmission provider will terminate the network customer's request and change the status of the request on OASIS to ''retracted.'' This termination will be without prejudice to the network customer submitting a new request that includes the required attestation. The network customer will be assigned a new priority consistent with the date of the new request.

416. In the event that the transmission provider or any network customer designates a network resource that it does not own or has not committed to purchase or that does not comport with the requirements for designated network resources, we will deem the network customer to be in violation of the *pro forma* OATT and will consider assessing civil penalties on a case-by-case basis consistent with the Commission's Enforcement Policy Statement. We encourage the transmission provider and other market participants to use the Commission's Enforcement Hotline to report instances when they believe a network customer has designated as a network resource a resource that does not meet the criteria for network resources.

c. Undesignation of Network Resources

417. Section 28.2 of the *pro forma* OATT requires the transmission provider, on behalf of its native load customers, to designate resources and loads in the same manner as any network customer under Part III of the *pro forma* OATT (Network Integration Transmission Service). The information provided by the transmission provider must be consistent with the information it uses to calculate ATC. Section 30.3 of the *pro forma* OATT allows the network customer to terminate the designation of all or part of a generating resource as a network resource at any time, though the network customer should provide notification to the transmission provider as soon as reasonably practicable.

418. In Order No. 888–B, the Commission clarified that the *pro forma* OATT allows network customers to designate network resources over shorter time periods. The Commission indicated that a network customer that seeks to engage in firm sales from its current designated network resources may terminate the generating resource (or a portion of it) as a network resource pursuant to section 30.3 of the *pro forma* OATT and request, as set forth in section 29 of the *pro forma* OATT, that the same generation resource be designated as a network resource effective with the end of its power sale.[379]

419. In the NOI, the Commission sought comment on whether network customers should be allowed to ''undesignate'' portions of their designated network resources on a short-term basis in order to make firm sales from these resources.

Comments

420. Most commenters suggest that the Commission continue to allow network customers to undesignate a portion of their designated network resources on a short-term basis in order to make firm sales.[380] APPA argues that the ability of network customers to undesignate their network resources on a short-term basis is an important aspect of Order No. 888–B and should be preserved. APPA states that the flexibility afforded to network resource customers allows them to lay off excess power supplies that they do not need to serve their designated loads during off-peak demand periods. APPA and EEI contend that this increases the number of wholesale sellers in the market during non-peak periods, and this supports wholesale competition for power supply sales.

421. Several commenters suggest that network customers should have the same right as transmission providers to undesignate network resources to make off-system sales.[381] APPA states that the Commission should make explicit the requirement that the transmission provider must provide the same flexibility to its network customers as it does to its own merchant function in designating and terminating network resources.

422. NRECA asserts that public utility transmission providers must be required to undesignate resources or portions thereof in order to make firm sales out of generation fleets that they have designated as a network resource.

[379] Order No. 888–B at 62,093

[380] *E.g.,* APPA, EEI, Entergy, Nevada Companies, Public Power Council, Southern, and TVA.

[381] *E.g.*, APPA, NRECA, and Public Power Council.

Discussion

423. We propose to continue to allow network customers to undesignate a portion of their network resources on a short-term basis to make off-system sales. We reiterate that a network customer may redesignate the resource by making a request to designate a new network resource. In response to comments that the transmission provider also should be required to undesignate network resources when the transmission provider makes firm off-system sales, we reiterate that the transmission provider must abide by both the requirement in section 28.2 of the *pro forma* OATT to designate its network resources in the same manner as network customers and the prohibition in section 30.1 of the *pro forma* OATT against making firm sales from its designated network resources. That is, the transmission provider and all network customers must designate their network resources and are prohibited from making firm sales from designated network resources. To the extent the transmission provider or a network customer wants to make a firm sale from a network resource, it must undesignate the resource pursuant to section 30.3 of the *pro forma* OATT. The network customer, including the transmission provider itself, can request to redesignate the resource by making a request to designate a new network resource pursuant to section 30.2 of the *pro forma* OATT.

424. We seek comment on the amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation.

7. Clarifications Related to Network Service

Secondary Network Service

425. Section 28.4 of the *pro forma* OATT allows a network customer to deliver economy energy purchases to its network load from non-designated network resources on an as-available basis without additional charge. In Order No. 888, the Commission described economy energy purchases as energy that displaces firm network resources.[382]

426. The use of secondary network service to deliver purchased power

[382] Order No. 888 at 21,751.

when a network customer is making off-system sales was raised in several Commission investigations and audits. In *Idaho Power*, the Commission accepted a settlement with Idaho Power related to Idaho Power's incorrect use of the native load priority to access its transmission system.[383] In *Idaho Power*, the utility's wholesale merchant function purchased power outside of Idaho Power's control area to facilitate an off-system sale and used secondary network service to bring the purchases into Idaho Power's control area.[384] In accepting the settlement, the Commission stated that ''[i]t is axiomatic that the native load priority cannot be used to complete sales that are not necessary to serve native load.'' [385] In *MidAmerican*, the Commission issued an audit report that contained a finding that MidAmerican's wholesale merchant function used network service instead of point-to-point service to deliver short-term energy purchases to its control area that were not used to serve MidAmerican's native load.[386]

Comments

427. South Carolina E&G asks the Commission to clarify whether specific methods used to bring sellers and buyers together in the wholesale market are appropriate under the *pro forma* OATT in its current form. South Carolina E&G notes that as a utility's native load forecasts evolve into real-time conditions, the utility may need to sell off excess energy. South Carolina E&G notes further that, as inexpensive sources of power become available off-system, the utility may engage in economy purchases of power for native load. South Carolina E&G asserts that such practices clearly benefit the market and safeguard native load customers' interests by ensuring that economy purchases minimize the price of consumers' power and/or giving the utility a market outlet for excess energy, thus avoiding the uneconomic backing down of lower cost generating units while retaining higher cost prescheduled purchases. South Carolina E&G urges the Commission to support the continuation of such practices.

Discussion

428. We propose to clarify that a network customer may not use secondary network service to bring energy onto its system to support an off-system sale if the purchased power does not displace the customer's own higher cost generation. We propose to modify the section 28.4 of the *pro forma* OATT to clarify that a network customer may use secondary network service to deliver economy energy and we propose to add a definition for ''economy energy'' to the *pro forma* OATT. We propose to define ''economy energy'' as energy purchased by a network customer that displaces the customer's own higher cost generation for the purpose of serving the customer's designated network loads.

429. While we reiterate that secondary network service may be used only to serve a network customer's designated network load, we do not intend to discourage market participants from identifying opportunities to profitably purchase for resale. We simply intend to ensure that all market participants compete on a comparable basis and use point-to-point service to complete all segments of a purchase for resale off-system.

430. We also do not intend to discourage network customers from purchasing off-system energy to lower the cost of serving network loads. A network customer may use secondary network service in hours when it is also making off-system sales. However, the network customer may do so only to deliver purchases that qualify as economy energy purchases. In response to South Carolina E&G's observation that a utility's native load forecasts evolve in real-time to the point that the utility may need to sell off excess energy that was purchased off-system, we note that our definition would allow a network customer to use network service to deliver off-system purchases when the network customer purchases the energy with the intent to serve native load.

431. In enforcing this policy, we will apply the definition of ''economy energy'' at the time the network customer commits to purchase energy. For instance, we will not take issue if a network customer uses secondary network service to deliver an hour-ahead purchase that costs less than the network customer's generation cost in the hour of operation. Similarly, we will not question the use of secondary network service by a network customer to deliver a day-ahead off-system purchase that costs less than the network customer's forecast generation cost, even if real-time system conditions evolve so that the realized generation cost is less than the cost of the purchased energy. We also would not take issue with a network customer that uses network service to deliver off-system block energy because the purchased energy is more economic than using its network resources, but makes off-system sales during some hours when the block energy purchase is scheduled. In other words, in enforcing this policy, we will apply the definition of ''economy energy'' as it applies to the entire period covered by the block purchase and not to a single hour within the block.

''[O]n an As-Available Basis''

432. Section 28.4 of the *pro forma* OATT allows a network customer to use secondary network service to deliver economy energy purchases to its network load from non-designated resources ''on an as-available basis.'' However, the current *pro forma* OATT does not specify how a network customer must arrange for secondary network service.

Discussion

433. We propose to modify section 28.4 of the *pro forma* OATT by clarifying that a network customer need not file an application for network service to receive secondary network service, but that all other requirements of Part III of the *pro forma* OATT (except for transmission rates) apply to secondary network service. In other words, a network customer must request secondary network service on OASIS in a manner consistent with *pro forma* OATT sections 18.1 and 18.2 (Procedures for Arranging Non-Firm Point-To-Point Transmission Service).

Redirect of Network Service

434. The current *pro forma* OATT does not include any provision to change the point of receipt for an off-system designated network resource, in a manner similar to redirect of point-to-point service. However, we are aware that several transmission providers have posted business practices that allow network customers either to substitute an off-system non-designated network resource for a designated network resource or to redirect the point of receipt associated with an existing network resource.

Discussion

435. We propose to clarify that network customers may not redirect network service in a manner comparable to the way customers redirect point-to-point service. Unlike point-to-point service that is based upon a contract-path model consisting of a designated point of receipt and point of delivery, network service involves no identified contract path and is therefore not a directable service. Rather, network

[383] *Idaho Power Co.*, 103 FERC ¶ 61,182 at P 2 (2003) (*Idaho Power*).

[384] *Id.* at P 4.

[385] *Id.*

[386] *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 at P 6 (2005).

service provides for the integration of designated network resources and loads using the entire transmission grid in a manner comparable to the transmission provider's use of the transmission grid to serve its native load customers. When a network customer wants to substitute one designated network resource for another, it should terminate the designation of the existing network resource and designate a new network resource. The network customer can then request to redesignate its original network resource by making a request to designate a new network resource. Alternatively, a network customer could use secondary network service when it wants to substitute a non-designated network resource for a designated network resource on an as-available basis.

8. Transmission Curtailments

436. Section 1.7 of the *pro forma* OATT defines curtailment as ''a reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.'' Curtailment provisions for point-to-point service are set forth in sections 13.7 and 14.7 for firm and non-firm transmission services respectively and the curtailment provisions for network service are contained in section 33. Complaints regarding improper curtailment of service by transmission providers have been made in a variety of proceedings and the Commission has found cases of improper curtailment in the past.[387]

437. In the NOI, the Commission asked whether there is evidence of improper curtailment practices by public utility transmission providers or customers that warrants reforms to the *pro forma* OATT. If there is, we requested that commenters provide specific examples of such practices. We also asked whether transmission providers engaging in improper curtailments should be subject to monetary penalties or other remedies for market manipulation.

Comments

438. EEI argues that there do not appear to be many instances of improper curtailments and many utilities state that they are not aware of any improper curtailments by public utility transmission providers. For example, Southern states that curtailments are performed on a non-discriminatory basis, in accordance with applicable OATT provisions. Ameren, KCP&L, and PNM–TNMP state that they are not aware of any improper practices that would warrant reforms to the *pro forma* OATT. APPA does not advocate changes to the *pro forma* OATT regarding curtailment, stating that its members express more concerns about the denial of service prior to and at the time of scheduling than they do regarding curtailment of service once it has commenced. However, APPA also notes that most of its members use firm service that is unlikely to be interrupted once it is scheduled. Public Power Council, Snohomish, MEAG and Salt River concur with APPA that OATT reforms are not needed for curtailments.

439. Transmission customers, particularly IPPs, generally have a different view, arguing that the reasons for curtailment are difficult to discern, and that information is often insufficient to determine whether curtailments have been performed correctly. Northwest IPPs state curtailments frequently appear arbitrary. Powerex argues that incomplete postings on many transmission systems and the lack of transparency in curtailment data could mask improper curtailment. Calpine states that it is usually difficult to determine whether a curtailment of service is truly justified by system reliability factors because the operational facts underlying the utility's curtailment decision are unknown. It argues that the criteria for utility curtailment decisions are not standardized, making it difficult to determine the propriety of curtailment decisions, particularly when curtailment is internal to a single area and not performed through the NERC TLR process. Calpine recommends that the terms and conditions for curtailments be standardized by the new reliability organizations created by EPAct 2005, that such terms and conditions be made a formal part of the *pro forma* OATT and the OATTs of public, private and federal utilities, and that these be posted on the transmission provider's OASIS. Calpine further recommends that regional NERC organizations be requested to audit the curtailment practices of all utilities that are not members of an RTO/ISO. Constellation asserts that TLRs are a ''blunt and inefficient mechanism'' for curtailment and calls for a requirement that transmission providers provide redispatch options.

440. In reply to claims that vertically integrated utilities provide inadequate information on curtailments, Southern states that existing OASIS requirements already require utilities to post a considerable amount of information on curtailments, and that the information currently posted is adequate to meet customers' needs. Nevertheless, Southern also states that while those rules have been effective in achieving their intended purpose, incremental additions to the information that is available through OASIS could assure customers that they have all of the information they need to make prudent decisions about transmission service and that they are being treated in a fair, equitable, and non-discriminatory way.

441. Commenters appear divided on the issue of whether there should be penalties for improper curtailments. The most common view, expressed by EEI and others, is that penalties for improper curtailments should be assessed only if the Commission finds that the transmission provider imposed the curtailment with the intent to treat a customer in an unduly discriminatory or preferential manner. Other commenters expressed a wide range of views. Alcoa states that improper curtailments should be the subject of monetary penalties. Santa Clara contends that transmission providers should be fully liable for any damages caused by improper curtailments. On the other hand, Southern argues that curtailment is a reliability issue and it would be unwise to subject transmission providers to after-the-fact assessments of their curtailment decisions. KCP&L notes that the responsibility for calling a TLR rests with the reliability coordinator, who makes decisions based on the NERC standard, so that penalties for improper curtailment activity should be a subject for the ERO.

Discussion

442. The Commission reminds both transmission providers and customers that our regulations require posting of transmission curtailment information on OASIS. The OASIS regulations state:

> When any transaction is curtailed or interrupted, the Transmission Provider must post notice of the curtailment or interruption on the OASIS, and the Transmission Provider must state on the OASIS the reason why the transaction could not be continued or completed.
>
> (ii) Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained and made available upon request, to the curtailed or interrupted customer, the Commission's Staff, and any other person who requests it, for three years.[388]

[387] *See, e.g., Consolidated Edison Co. of N.Y.* v. *Public Serv. Elec. & Gen. Co.*, 108 FERC ¶ 61,120 (2004).

[388] We note that we are proposing to change this information retention period to five years, consistent with our other proposed changes to the OASIS information retention provisions.

(iii) Any offer to adjust the operation of the Transmission Provider's system to restore a curtailed or interrupted transaction must be posted and made available to all curtailed and interrupted Transmission Customers at the same time.[389]

443. Those commenting that they have inadequate information about curtailments do not clearly state whether the source of this deficiency lies in: (1) The inadequacy of our standards, (2) inadequate compliance with these standards, (3) difficulties in dealing with the way the information is provided, or (4) some other area. We are, however, mindful that objective review of curtailments can require a considerable amount of information, some of which may not be provided under the present OASIS regulations, or may be provided in an inefficient manner. For example, we recognize that it is difficult for a customer to determine what network resources were available to the transmission provider that could have been redispatched consistent with *pro forma* OATT sections 30.5 and 33.2 to relieve the transmission constraint that led to a transmission curtailment. Another example may be discerning which discrete transaction(s) could be curtailed on a non-discriminatory basis to effectively relieve the constraint consistent with *pro forma* OATT section 13.6. We seek comment on whether additional requirements would improve the transparency of transmission curtailment information and the ability of customers to make use of that information.

444. With respect to the imposition of penalties, the Commission recognizes that the transmission curtailment decision is a reliability decision that should be based on applicable reliability standards. Moreover, we note that the need for transmission curtailment depends on many factors outside the control of an individual transmission provider, including loop flows throughout an interconnection. Accordingly, we will not propose generic penalties for improper transmission curtailments in this rulemaking. However, the absence of generic penalties should not be construed to mean that we will tolerate intentional behavior that subjects customers to unduly discriminatory or preferential actions. We remain vigilant in monitoring for intentionally discriminatory provision of transmission service, and stand ready to use our enforcement powers and penalty authority when needed.

9. Standardization of Rules and Practices

445. In Order No. 888, the Commission required each public utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce to file, pursuant section 205 of the FPA, a *pro forma* OATT under which it would provide open access transmission services. However, certain rules, standards and practices governing the provision of such transmission service (*e.g.*, public utility business practices) are not reflected in the *pro forma* OATT. Only when a public utility adopts a rule, standard or practice that significantly affects its rates and services has the Commission required it to make a filing pursuant to FPA section 205 to amend its OATT.[390] The Commission has applied this policy using a ''rule of reason'' test.[391]

446. The rule of reason test has arisen primarily with respect to protocols or operating procedures used by RTOs and ISOs. For example, the Commission has held that while the business practices manuals of the Midwest ISO implicate the Commission's jurisdiction because they generally involve ''the installation, operation, or use of facilities for the transmission or delivery of power * * * in interstate commerce,'' they do not require a FPA section 205 filing because ''they mostly involve general operating procedures.''[392] In other cases, the facts have required the filing of the rule, standard or practice. For example, CAISO proposed to post certain, technical, operational and business standards related to dynamic scheduling on its Web site and include only the rates under its OATT. There, the Commission found that the details contained in the standards are practices that may affect the terms and conditions of service significantly, and therefore, under the Commission's ''rule of reason,'' must be filed under FPA section 205.[393]

447. In the NOI, the Commission asked: (1) Whether all rules, standards and practices should be required to be included in public utilities' OATTs? (2) If not all, which of such rules, standards and practices should be included in public utilities' OATTs? and (3) Should rules, standards and practices not required to be included in public utilities' OATTs be required to be posted on OASIS to increase transparency?

Included in Open Access Transmission Tariffs

448. Some commenters argue that the rules, standards and practices governing the provision of transmission service should be included in public utilities' OATTs.[394] Occidental states that the inclusion of rules, standards and practices governing the provision of transmission service in public utilities' OATTs will add much needed clarity as to how transmission service is provided. EPSA states that while it may not be necessary, or desirable, to require all business practices to be incorporated into the OATT, there have been instances where transmission providers have adopted business practices that are inconsistent with their OATT requirements or that should have been filed as OATT amendments. Some commenters also support the inclusion of the NAESB standards in the OATT.[395]

449. In contrast, some commenters oppose including rules, standards and practices in the OATT.[396] EEI argues that rules, standards and practices should not be included as part of an OATT unless they significantly affect rates and service under the OATT. EEI states that this is consistent with the Commission's current practice for the inclusion of manuals in an OATT. Indicated New York Transmission Owners state that the inclusion of rules, standards and practices in the OATT is

[389] 18 CFR 37.6(d)(3) (2005).

[390] *E.g., Cleveland* v. *FERC,* 773 F.2d 1368, 1376 (D.C. Cir. 1985).

[391] *See, e.g., Public Serv. Comm'n of N.Y.* v. *FERC*, 813 F.2d 448, 454 (D.C. Cir. 1987) (holding that the Commission properly excused utilities from filing policies or practices that dealt only with matters of ''practical insignificance'' to serving customers); *Midwest Independent Transmission System Operator, Inc.*, 98 FERC ¶ 61,137 at 61,401 (''It appears that the proposed Operating Protocols could significantly affect certain rates and service and as such are required to be filed pursuant to Section 205.''), *order granting clarification,* 100 FERC ¶ 61,262 (2002).

[392] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 at P 656, 658, *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043, *order on reh'g*, 112 FERC ¶ 61,086 (2005); *see also PJM Interconnection, L.L.C.*, 81 FERC ¶ 61,257 at 62,267 (1997) (finding no reason to require filing of the PJM Manuals but requiring that such manuals be available for public inspection on a permanent basis), *order on reh'g*, 92 FERC ¶ 61,282 (2000).

[393] *California Independent System Operator Corp.*, 107 FERC ¶ 61,329 at P 21–22 (2004); *see also Southwest Power Pool, Inc.*, 112 FERC ¶ 61,303 at P 25 (2005) (requiring that the SPP OATT provide sufficient information for market participants to fully understand SPP's implementation of an imbalance market), *reh'g dismissed*, 113 FERC ¶ 61,115 (2005); *PJM Interconnection, L.L.C.*, 104 FERC ¶ 61,124 at P 61 (requiring PJM to place all procedures, standards and requirements for proposing that a transmission owner construct a specific upgrade, and all procedures for charging customers, in its tariff, not in its manuals), *order on reh'g*, *PJM Interconnection, L.L.C.*, 105 FERC ¶ 61,123 (2003).

[394] *E.g.,* Occidental, TAPS, and Williams.

[395] *E.g.*, Salt River and Snohomish.

[396] *E.g.*, BPA, EEI, MidAmerican, and Southern.

unnecessary and would administratively encumber any future revisions to the practices and rules by requiring conforming tariff filings.

Posted on OASIS

450. Several commenters believe it would be appropriate to post rules, standards and practices on public utilities' OASIS sites.[397] For example, EEI states that it would be appropriate to post all rules, standards and practices that are not part of the OATT on a transmission provider's OASIS. APPA asserts that, in particular, transmission providers should post the methodologies they use to develop ATC and ATC calculations should be periodically verified by an independent third party.[398]

451. Other commenters contend that rules, standards and practices should be posted on public utilities' OASIS sites only when they are not required to be filed.[399] TAPS argues that any rules, standards and practices not required to be filed must be publicly posted on the transmission provider's OASIS to provide needed transparency, because including essential terms in business practices that are not posted makes it very difficult for customers to understand if they are being treated fairly by the transmission provider. TDU Systems asserts that requiring posting on transmission providers' OASIS sites of any standards and practices not included in their OATTs would facilitate transactions across several transmission provider systems, especially where transmission providers are not participating in RTOs or ISOs.[400] Williams goes one step further and recommends that the Commission require that transmission providers both file with the Commission and post on their OASIS sites, all policies, practices and interpretations used or relied upon to evaluate a request for transmission service.

Discussion

452. There appears to be broad consensus among the commenters that rules, standards and practices not required to be included in a transmission provider's *pro forma* OATT should be posted on the transmission provider's OASIS. We agree and propose to require transmission providers to post on OASIS all of their rules, standards and practices that relate to transmission services. We believe this proposal will provide greater transparency and mitigate the potential for undue discrimination against customers taking transmission service under the transmission provider's OATT.[401] However, we seek comment on how to determine what ''relates'' to transmission service to facilitate a consistent interpretation and to minimize discretion on what rules, practices and standards should be posted on OASIS.[402]

453. Commenters presented wide ranging positions on the issue of what rules, standards and practices to include in the OATT. We do not propose to modify our existing policy on this issue at this time.[403] We agree with EPSA's concern that requiring transmission providers to include all of their rules, standards and practices in their OATTs could decrease a transmission provider's flexibility to change businesses practices and respond to the requests of customers. Additionally, we believe that requiring transmission providers to file all of their rules, standards and practices in their OATTs would be impractical and potentially administratively burdensome.[404]

454. We propose to require, however, that creditworthiness and security requirements be included in a transmission provider's OATT. The creditworthiness provision in section 11 of the *pro forma* OATT authorizes transmission providers to require ''reasonable credit review procedures'' in accordance with ''standard commercial practices,'' to determine the ability of transmission customers to meet service obligations. Furthermore, to protect transmission providers from the risk of non-payment, the provision authorizes the transmission provider to require as security a letter of credit or other forms of security consistent with the Uniform Commercial Code. In the Creditworthiness Policy Statement, the Commission explained that non-RTO or -ISO transmission providers generally have not incorporated creditworthiness or security requirements into their OATTs.[405] The Commission stressed that transparency of credit procedures and security requirements can enhance market certainty and liquidity by allowing customers to determine for themselves the information they need to demonstrate creditworthiness and the amount and type of security they need to receive transmission service. In interpreting the ''reasonable credit review procedures'' requirement in section 11 of the *pro forma* OATT, the Commission stated that it expected transmission providers to post on their OASIS sites the process and methodologies used to evaluate a potential customer's creditworthiness and calculate the necessary security.[406] But it also stated that it would ''consider standardizing credit procedures through a generic rulemaking if necessary to prevent undue discrimination.''[407]

455. Our preliminary conclusion is that a transmission provider's OATT should contain sufficient information about its credit process and requirements to enable customers to understand the information required to demonstrate creditworthiness and to determine for themselves the general amount and type of security they may need to provide in order to receive service. We therefore propose to amend section 11 of the *pro forma* OATT on creditworthiness to require each transmission provider to include its creditworthiness and security requirements in a new Attachment L to its OATT.

[397] *E.g.*, APPA, BPA, EEI, EPSA, MidAmerican, and Southern.

[398] *See supra* Part V.A addressing posting requirements for ATC calculation.

[399] E.g., Progress Energy and TAPS.

[400] Suez Energy NA emphasizes that the posting of rules, standards, and practices on OASIS merely ensures that they are transparent, it does not ensure that they are non-discriminatory.

[401] We clarify that posting rules, practices and standards on the transmission provider's OASIS—in lieu of filing such practices with the Commission as part of the transmission provider's *pro forma* OATT—neither insulates a transmission provider from complaints nor confers a just and reasonable presumption. We encourage customers to call the Commission's Enforcement Hotline with complaints about the application of such rules, standards and practices should they experience problems with their transmission providers. To the extent customers are not satisfied with responses from utilities, they should contact the Commission's Enforcement Hotline via telephone (202) 502–8390, toll-free 1–888–889–8030, fax (202) 208–0057, or at *www.ferc.gov/cust-protect/enforce-hot.asp*.

[402] We note that certain rules and practices are already required to be posted on OASIS. *See, e.g., Order No. 889; Open Access Same-Time Information Systems,* Order No. 605, 64 FR 34117 (Jun. 25, 1999), *FERC Stats. and Regs.* ¶ 31,075 (1999); Order No. 676.

[403] *See supra* notes 391–393 and accompanying text.

[404] Of course, we will require the filing of certain rules, standards and practices when circumstances require. In Order No. 676, the Commission, among other things, incorporated certain business standards developed by NAESB by reference into the Commission's regulations and required public utilities to file revisions to their OATTs to include these standards. Order No. 676 at P 20.

[405] *Policy Statement on Electric Creditworthiness*, 109 FERC ¶ 61,186 at P 9 (2004) (Creditworthiness Policy Statement).

[406] *Id.* at P 12. The Commission explained that all transmission providers (including RTOs and ISO) were expected to ''(1) make their credit-related practices more transparent and comprehensive; (2) post on their [OASIS sites] the procedures that they use to do their credit analyses; and (3) provide a customer with a written analysis setting forth how that entity applied its credit standards to that customer, if that customer is required to provide security.'' *Id.*

[407] *Id.* at P 15.

456. In the Creditworthiness Policy Statement, the Commission explained that, to assess an applicant's credit risk, transmission providers should use both qualitative factors, such as the local regulatory environment or the applicant's history and financial policies, and quantitative factors, such as information included on the applicant's financial statements.[408] We propose to require the new Attachment L to include such quantitative and qualitative criteria to determine the level of secured and unsecured credit. We also propose to require the new Attachment L to include the following elements: (1) A summary of the procedure for determining the level of secured and unsecured credit; (2) a list of the acceptable types of collateral/security; (3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements; (4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements; (5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and (6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination. We propose to allow these basic elements to be supplemented with a credit guide or manual to be posted on OASIS.

457. Though we are proposing to require transmission providers to incorporate the creditworthiness and security methodologies into their OATTs, we recognize that there is a balance here between the burden on the transmission provider of adding these methodologies to its OATT and the need for Commission review and approval if methodologies frequently change. We seek comment on whether the proposal is unduly burdensome.

10. OATT Definitions

458. In the NOI, the Commission requested comment on whether new or amended *pro forma* OATT definitions were necessary. The Commission also noted that new section 215(a)(4) of the FPA, which was adopted as part of EPAct 2005, defines the term ''reliable operation.'' [409] We therefore asked whether this definition should be incorporated in the *pro forma* OATT.

459. Though MidAmerican urges the Commission to incorporate the definition of ''reliable operation'' into the *pro forma* OATT, other commenters argue that the definition of reliable operation should not be included in the *pro forma* OATT.[410] Southern argues that the definition of reliable operation included in section 215 of the FPA would impose a higher standard on transmission providers than is currently required by well-established NERC standards. Southern and EEI assert that the system is not planned to be able to guarantee that operations will not be impaired under any conditions. Southern argues that transmission providers should not be held to a higher standard of having to ensure that the system can continue to be operated even if a ''sudden disturbance, including a cybersecurity incident or unanticipated failure of system elements'' occurs.

460. Along with Southern, EEI contends that the ERO should establish standards related to reliable operation. EEI states that section 215 of the FPA simply gives the Commission jurisdiction over reliability standards, which are defined as standards for the reliable operation of the transmission system; it does not require transmission providers to meet a ''reliable operation'' standard. This is an important distinction, EEI continues, because while a transmission provider may adopt reasonable reliability standards, that does not guarantee that it will in all instances meet a ''reliable operation'' requirement, which would require the transmission provider to in all instances prevent instability, uncontrolled separation or cascading failures despite sudden disturbances, cybersecurity incidents, or unanticipated failures of system elements. EEI and Southern contend that because the ERO will implement the directives of Congress contained in section 215, the ERO will be best suited to establish the reliability standards that incorporate principles of reliable operation.

461. TAPS suggests that what is more important than adding a ''reliable operation'' definition is making explicit in the tariff what the Commission stated in its Policy Statement on Matters Related to Bulk Power System Reliability (Reliability Policy Statement) [411]—that transmission provider obligations under the *pro forma* OATT are subject to an overriding ''Good Utility Practice'' requirement that includes compliance with NERC reliability standards or more stringent regional reliability council standards.

Discussion

462. We propose to require transmission-owning public utilities to modify the definition of Good Utility Practice in their respective OATTs to reference the reliable operation definition adopted in section 215 of the FPA. We propose to take this action for two reasons. First, the Commission indicated in the Reliability Policy Statement that it expects public utilities operating transmission facilities under the *pro forma* OATT to conform to prevailing reliability standards. The Commission finds that referencing the reliable operation definition in section 215 of the FPA satisfies our requirement that transmission providers provide safe and reliable transmission service to customers taking service under the *pro forma* OATT. Second, we are mindful of the obligation placed on ''all users, owners and operators of the bulk power system'' under section 215(b) of the FPA to ''comply with reliability standards'' that will take effect under this section. Those reliability standards must ''provide for reliable operation of the bulk-power system.'' [412] When the ERO is certified by the Commission and we approve its reliability standards, those standards will be based on the same definition of reliable operation we propose to incorporate into the *pro forma* OATT. We agree with EEI and Southern that the ERO is best suited to develop reliability standards for the Commission's approval, but our proposal to incorporate the definition of reliable operation does not establish a reliability standard; rather, we believe it reflects Congress's benchmark for acceptable utility practice. It therefore belongs in our definition of Good Utility Practice in the *pro forma* OATT.

463. In addition to amending the definition of Good Utility Practice, we propose to add a definition for ''non-firm sales'' to clarify section 30.4 of the *pro forma* OATT. A number of transmission providers have modified section 30.4 of the OATT to state that ''The Network Customer shall not operate its designated Network Resources located in the Network

[408] *Id.* at P 13 & nn.13–14. An evaluation using both sets of factors would allow an applicant without a credit rating or a strong balance sheet, but with solid credit, to meet the creditworthiness criteria. *Id.* at P 14.

[409] EPAct 2005 sec. 1211(a) (to be codified at FPA section 215(a), 16 U.S.C. 824o). Section 215(a)(4) defines ''reliable operation'' as ''operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.''

[410] *E.g.*, EEI, Powerex, Snohomish, Southern, Suez Energy NA, and TAPS.

[411] *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 at P 23, *clarified*, 108 FERC ¶ 61,288 (2004); *Supplement to Policy Statement on Matters Related to Bulk Power System Reliability*, 110 FERC ¶ 61,096 (2005).

[412] Section 215(a)(3) of the FPA.

Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus non-firm sales delivered pursuant to Part II of the Tariff, plus losses'' (emphasis added). We propose to define ''non-firm sales'' as ''an energy sale for which delivery or receipt of the energy may be interrupted for any reason or for no reason, without liability on the part of either the buyer or seller.'' This is the definition of non-firm sales used in a number of industry-standard master power sales agreements, including the EEI Master Purchase and Sale Agreement. We propose to clarify that, for the purposes of applying section 30.4 of the *pro forma* OATT, energy sales that can only be interrupted to maintain system reliability will be considered firm sales.

464. We also propose to add two new definitions that are required to implement our proposed reforms. For example, we propose a definition of ''affiliate'' in section 1.1 of the revised *pro forma* OATT incident to our proposed change to the pricing of reassigned capacity. We also propose a new definition of ''pre-confirmed application'' in section 1.40 of the revised *pro forma* OATT incident to our proposal to give priority to requests that are pre-confirmed.

E. Enforcement

1. General Policy

a. Compliance Review Regime

Comments

465. A number of commenters indicate that a strong program to audit compliance with the *pro forma* OATT is crucial to preventing undue discrimination in the provision of transmission service. APPA argues that the Commission should establish a regime of systematic tariff compliance reviews because the OATT is at bottom a behavioral remedy rather than a structural one, so active Commission oversight is necessary. In addition, APPA notes that OATT transmission customers (especially network customers that are dependent upon the transmission systems of their neighboring public utility OATT transmission providers) are often reluctant to open the ''can of worms'' that filing a section 206 complaint against their transmission providers entails. Powerex urges the Commission to establish systematic tariff compliance audits as a monitoring tool because remedies and penalties alone are structurally ill-suited to address the myriad of idiosyncratic deviations from the Commission's policies and standards that currently exist. TAPS asserts that, while customer complaints are an indication that something is awry, the lack of transparency makes it very hard for customers to detect discrimination and tariff violations on the part of the transmission provider. TAPS suggests that customers often conclude that a complaint process is not cost effective because even if they ultimately prevail, they will have lost out on the purchase opportunity that prompted the complaint.

Discussion

466. The Commission intends to maintain a strong audit program to determine whether transmission providers and transmission customers are in compliance with the new *pro forma* OATT. This audit program will include operational audits similar to the OATT compliance components of audits conducted by Commission staff in the past.

467. These audits will determine compliance with specific provisions of the OATT. Staff's findings and recommendations will be detailed in public audit reports issued in accordance with the Commission's authority. If an audit is contested, it will be disposed of consistent with the Commission's final rule on disposition of contested operational audits. The Commission staff's compliance audits historically have included the collection of information regarding the audit target's overall operations. In this vein, the Commission staff's OATT compliance audits may also collect information regarding implementation of a transmission provider's OATT, with the intent that Commission staff may share the information it gathers with the Commission subject to all applicable ex parte rules.

b. Use of Independent Third Party Audits

Comments

468. A number of commenters indicate that the Commission should not rely on third party audits as the primary means of ensuring compliance with the OATT. APPA states that if an OATT Transmission Provider retains and pays an ''independent reviewer'' to prepare compliance audit reports, someone will inevitably question the reviewer's independence. Therefore, APPA argues that it might be better for the Commission itself to prepare the reports, or to retain a consultant to do so. Southern suggests that the Commission's existing mechanisms, coupled with new rules that will ensure that all regulated entities subject to investigations or audits are afforded their full due process rights, should be adequate to ensure compliance with OATT provisions.

469. A number of commenters also indicate that the Commission should require third party audits for frequent abusers. EEI suggests that a transmission provider that is found to have a systematic or continuing violation of the OATT could be required to hire an independent reviewer to monitor its future compliance for a period of time after the violation occurred. TVA suggests that, if a particular transmission provider repeatedly misapplies its OATT, the Commission should at that point consider requiring that transmission provider to hire an independent monitor for a defined period of time as a remedy for those actual infractions. NRECA argues that those transmission providers who are consistently in violation or who do not cure audit findings in a timely manner should see both an increase in frequency and further scrutiny from the audit process.

Discussion

470. We propose to have Commission staff conduct audits of compliance with the new OATT. Commission staff is in a unique position to conduct OATT compliance audits and recommend remedial action consistent with previous audits. In addition, entities audited by Commission staff now have clear and assured due process rights as the result of Order No. 675.

471. We may require third party audits as part of an individual compliance plan we order an audited party to undertake when we issue the Commission staff's audit report. The Commission staff monitors compliance with all of its audit recommendations as part of its regular practice. We may, in selected cases, decide to enhance this regular monitoring by requiring an audited party to hire an independent reviewer to continue compliance audits after the Commission staff's audit has ended. We could take such action in response to a number of circumstances, including, but not limited to, identification of systematic OATT violations, violations that require on-going monitoring, or a pattern of repeated OATT violations. Under these circumstances, the audited party should bear the burden of on-going compliance monitoring. If we decide to order independent OATT compliance audits as part of an individual audited party's compliance plan, we will specify the scope and duration of the audits.

2. Civil Penalties

a. Background

472. The NOI observed that the existing OATT allows transmission providers to impose certain operational penalties on customers for tariff violations, but does not address the adverse consequences to a transmission provider who violates its OATT. It also summarized the broad variety of remedies and sanctions available for enforcement of its rules and regulations, including the enhanced civil penalty authority provided by EPAct 2005.[413]

473. In the NOI, the Commission asked for comments on whether we should address the issue of remedies or penalties against transmission providers as part of OATT reform. It also asked if transmission providers should be subject to revocation of their market-based rate authority for certain OATT violations, and if certain violatins should be considered market manipulation under the Market Behavior Rules[414] and section 1283 of EPAct 2005.[415]

474. Subsequent to the NOI, on October 20, 2005 the Commission issued its Enforcement Policy Statement, which discusses the factors the Commission will take into account in determining remedies and sanctions for violations, including civil penalties.[416] Also, in EPAct 2005, Congress provided the Commission with specific anti-manipulation authority.[417] On January 19, 2006, to implement this new authority, the Commission issued Order No. 670 (Anti-manipulation Rule),[418] adopting a new Part 1c of its regulations, under which it is ''unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, (1) to use or employ any device, scheme, or artifice to defraud, (2) to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (3) to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity.''[419] The Anti-manipulation Rule made it unnecessary to retain Market Behavior Rules 2 or 6. Accordingly, on February 16, 2006, the Commission rescinded Market Behavior Rules 2 and 6 and codified the substance of Market Behavior Rules 1, 3, 4, and 5 in the Commission's regulations.[420]

b. Whether Civil Penalties Should Be Specified in the OATT

Comments

475. Commenters often did not distinguish between operational penalties and civil penalties in their comments about the need for additional penalties in the OATT. EEI and MidAmerican made the distinction, asserting that civil penalties should not be specified in the OATT. They and others contend that: enforcement actions, including civil penalties, should be reviewed on a case-by-case basis;[421] civil penalties should be based upon the seriousness of the violation;[422] penalties should require proof of intent or willfulness;[423] penalties should only apply for repeated violations;[424] and, penalty procedures should provide for due process.[425]

Discussion

476. The Commission intends to enforce OATT provisions in a firm but fair manner. For example, the Commission elsewhere is proposing that transmission providers as well as transmission customers be subject to specified operational penalties for violations of certain OATT provisions. However, aside from these operational penalties, the Commission does not intend to provide a schedule of enforcement remedies and sanctions in the OATT. Instead, the Commission prefers to examine violations and determine the appropriate response for a violation on a case-by-case basis. The Commission has a broad array of equitable remedies and sanctions for violations.[426] Our enhanced civil penalties, as provided by EPAct 2005, are among the available sanctions for violations of the Commission's statutes, rules, regulations and orders, including instances of undue discrimination and market manipulation.

477. Although we will look at violations on a case-by-case basis and not identify in this proposed rule specific penalties for different violations, the Enforcement Policy Statement provides guidance and regulatory certainty regarding enforcement and places entities subject to our jurisdiction on notice of the consequences of violations.[427] As we noted, ''[I]t is important that we retain the discretion and flexibility to address each case on its merits, and to fashion remedies appropriate to the facts presented, including any mitigating factors.''[428]

478. As the facts of a specific matter warrant, we will seek disgorgement of unjust profits that are the result of a violation. Violators should not retain the gains acquired as the result of the violation. OATT violators will be expected to disgorge unjust profits whenever they can be determined or reasonably estimated.[429] In addition, as warranted by the facts, civil penalties may also be assessed. Those penalties (up to $1 million per day per violation), however, can be mitigated by the factors set forth in the Enforcement Policy Statement, such as self-reporting, compliance programs, and cooperation

[413] EPAct 2005 expanded the Commission's civil penalty authority under the FPA to encompass violations of all provisions of FPA Part II (EPAct 2005 section 1284(e)(1) (to be codified at section 316A of the FPA, 16 U.S.C. 825o–1)), and established the maximum civil penalty the Commission can assess under FPA Part II as $1 million per day per violation (EPAct 2005 section 1284(e)(2) (to be codified at section 316A of the FPA, 16 U.S.C. 825o–1)).

[414] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 (2003), *order on reh'g*, 107 FERC ¶ 61,175 (2004).

[415] NOI at P 15.

[416] *Enforcement of Statutes, Order, Rules and Regulations*, Policy Statement on Enforcement, 113 FERC ¶ 61,068 at P 17–20 (2005) (Enforcement Policy Statement).

[417] EPAct 2005 sec. 1283 (to be codified at section 222 of the FPA, 16 U.S.C. 824v). Congress prohibited the use or employment of ''any manipulative or deceptive device or contrivance'' in connection with the purchase or sale of electric energy or transmission services subject to the jurisdiction of the Commission. Congress directed the Commission to give these terms the same meaning as under the Securities Exchange Act of 1934, 15 U.S.C. 78j(b) (2000).

[418] *Prohibition of Energy Market Manipulation*, Order No. 670, 71 FR 4244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202, *reh'g denied*, 114 FERC ¶ 61,300 (2006).

[419] *Id.*, 71 FR 4244, 4258 (Jan. 26, 2006) (to be codified at 18 CFR 1c.2(a)).

[420] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 114 FERC ¶ 61,165 (2005). The primary purpose of the Market Behavior Rules was to prohibit market manipulation by public utility sellers acting under market-based rate authority.

[421] *E.g.*, Entergy, Santa Clara, Steel Manufacturers Association, WAPA, and Williams.

[422] Steel Manufacturers Association.

[423] *E.g.*, EEI, KCP&L, Progress Energy, Public Power Council, Southern, and Xcel.

[424] *E.g.*, Alberta Intervenors, Public Power Council, Snohomish, Suez Energy NA, and TDU Systems.

[425] *E.g.*, Bonneville, EEI, Southern, and Nevada Companies.

[426] Enforcement Policy Statement at P 4. The ''enhanced civil penalty authority will operate in tandem with our existing authority to require disgorgement of unjust profits obtained through misconduct and/or to condition, suspend, or revoke certificate authority or other authorizations, such as market-based rate authority for sellers of electric energy.'' *Id.* at P 12.

[427] *Id.* at P 1.

[428] *Id.* at P 13. Several commenters supported the application of the Enforcement Policy Statement to OATT violations. *E.g.*, APPA, EEI, Midwest SATs, National Grid, and TAPS.

[429] Enforcement Policy Statement at P 19 and P 23.

with staff from the Commission's Office of Enforcement.[430]

c. Whether Transmission Providers Should Be Subject to Revocation of Their Market-Based Rates for OATT Violations.

Comments

479. In the NOI, the Commission also asked if transmission providers should be subject to revocation of their market-based rate authority for certain OATT violations.[431] Some commenters agree that revocation of market-based rates could be an appropriate remedy.[432] EPSA asserts that revocation of market-based rate authority should be among the penalties the Commission could impose for serious violations of the OATT, such as when more transmission capacity is set aside than is actually needed to serve native load, or undue preferences are extended to native load or affiliate transactions. TAPS states that where lack of ATC forecloses network customer access to alternatives, a transmission provider should not be able to make sales of electric power at market-based rates and should be required to offer embedded-cost-based sales. APPA asserts that whether a transmission provider's violation of the OATT merits possible revocation of its market-based rate authority depends on the nature and severity of the violation. APPA argues that if the violation concerns practices that favor the transmission provider's own wholesale merchant function at the expense of its third-party competitors, and if that violation is willful or repeated, then revocation or conditioning of the market-based rate authority of the transmission provider's merchant function may be warranted.[433]

480. Other commenters argue that revocation of market-based rate authority should be reserved for market behavior violations, not OATT violations.[434] EEI and MidAmerican argue that the Commission has separated public utilities' transmission functions from their marketing functions and, thus, penalties for violation of the OATT should be kept separate from penalties imposed for market behavior violations. PacifiCorp contends that the Commission's new penalty authority is sufficient to ensure compliance with the OATT and that there no longer is a need to consider revocation of market-based rate authority. Progress Energy states that the Commission should not penalize the utility's merchant function for violations of the OATT caused by the utility's transmission function. Ameren and Southern would add a ''willful'' or ''intent'' requirement to revoking market-based rates for an OATT violation.

Discussion

481. As discussed in the Enforcement Policy Statement, the better approach is to look at all of the facts and circumstances of each violation before deciding on any remedy or sanction.[435] There may be OATT violations in circumstances that, after applying the factors in the Enforcement Policy Statement, merit revocation or limitation of market-based rate authority. However, before the Commission will consider revoking an entity's market-based rate authority for a violation of the OATT, there must be a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority. The Commission proposes that if it determines, as a result of a significant OATT violation, that the market-based rate authority of a transmission provider will be revoked within a particular market, each affiliate of the transmission provider that possesses market-based rate authority will have it revoked in that market on the effective date of revocation of the transmission provider's market-based rate authority.

d. Whether Certain OATT Violations Should Be Considered Market Manipulation Under the Market Behavior Rules and Section 1283 of EPAct 2005.

Comments

482. In the NOI, the Commission asked if specific OATT violations should be considered market manipulation under the Market Behavior Rules and section 1283 of EPAct 2005.[436] The Commission then suggested that one such type of violation might be when a transmission provider sets aside more transmission capacity than is needed to serve native load, but uses the capacity for third-party sales.[437]

483. None of the commenters want specific violations identified in the OATT to be deemed per se market manipulation. Some commenters prefer to have the Commission approach these matters on case-by-case basis.[438]

484. Some commenters, like Constellation, identify OATT violations that may constitute market manipulation. Ameren, EEI, and Occidental argue that intentionally setting aside more transmission capacity than is needed to serve native load could constitute market manipulation. LG&E states that the key factor is ''intent.'' LG&E provides an example in which ATC becomes available as a result of less-than-expected native load requirements, and not because the transmission owner intentionally overstated native load requirements, and the transmission owner's affiliate followed proper reservation and scheduling protocol in a manner applicable to all potential transmission customers. Under these circumstances, LG&E contends, the Commission's imposition of a civil penalty would be inappropriate given the absence of intent to impart false or misleading information into the marketplace or hoard transmission.

485. Occidental suggests that curtailments of firm transmission service designed to permit wholesale power sales by the merchant function of the transmission provider or an affiliate should also be considered market manipulation. Suez Energy NA argues that incidents of affiliate abuse by a transmission provider may be considered market manipulation pursuant to section 1283 of EPAct 2005. TAPS states that certain withholding of transmission capacity can rise to the level of a violation of the Commission's market behavior rules and its new anti-manipulation authority if the withholding reduces the supply of both transmission and generation in a market, which artificially raises prices.

Discussion

486. As explained above, we now are examining market manipulation in the context of Part 1c of our regulations. We do not propose to identify in the OATT specific conduct as per se market manipulation. As noted in Order No. 670, market manipulation is a fact-intensive determination.[439] We do not want to restrict our fact-finding to specific types of violations. Although certain fraudulent or deceptive practices concerning the OATT could qualify as market manipulation under Order No. 670, the Commission declines to address such circumstances generically

[430] *Id.* at P 6 and P 21–27.

[431] NOI at P 15.

[432] *E.g.,* Arkansas Cities, NRECA, Occidental, Snohomish, and Williams.

[433] APPA at 32.

[434] *E.g.,* EEI, MidAmerican, PacifiCorp, PNM–TNMP, and Progress Energy.

[435] Enforcement Policy Statement at P 18. Among the factors examined are ''willfulness'' and ''intent'' of the violator. *Id.* at P 20.

[436] NOI at P 15. Section 1283 of EPAct 2005 establishes section 222 of the FPA (to be codified at 16 U.S.C. 824v).

[437] NOI at P 15.

[438] *E.g.,* APPA, Entergy, Nevada Companies, Public Power Council, and Southern.

[439] Anti-manipulation Rule at P 72.

in this rulemaking and instead will consider them on a case-by-case basis, if and when they arise, under the standards set forth in Order No. 670.

VI. Information Collection Statement

487. The following collections of information contained in this proposed rule have been submitted to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995.[440] OMB's regulations require OMB to approve certain information collection requirements imposed by agency rule.[441]

488. Comments are solicited on the need for this information, whether the information will have practical utility, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

Burden Estimate: The public reporting and records retention burdens for the proposed reporting requirements and the records retention requirement are as follows.[442]

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
Part 35 (FERC–516):				
Conforming tariff changes	176	1	25	4,400
Revision of Imbalance Charges	176	1	5	880
ATC revisions	176	1	40	7,040
Planning (Attachment K)	176	1	100	17,600
Congestion studies	176	1	250	44,000
Attestation of network resource commitment	176	1	1	176
Quarterly Reports for capacity reassignment	176	1	60	10,560
Operational Penalty annual filing	176	1	10	1,760
Creditworthiness—include criteria in the tariff	176	1	40	7,040
Sub Total Part 35				93,456
Part 37 (FERC–717):				
ATC-related standards.				
NERC/NAESB Team to develop	1	1	1,920	1,920
Review and comment by utility	176	1	20	3,520
Implementation by each utility	176	1	40	7,040
Mandatory data exchanges	176	1	80	14,080
Explanation of change of ATC values	176	1	100	17,600
Reevaluate CBM and post quarterly	176	1	20	3,520
Post OASIS metrics; requests accepted/denied	176	1	80	14,080
Posting of metrics for System Impact Studies	176	1	100	17,600
Post all rules to OASIS	176	1	5	880
Sub Total (Part 37)				80,240
Total (Part 35 + Part 37)				173,696
Recordkeeping	176	1	30	5,280

Total Annual Hours for Collection:
Reporting + recordkeeping hours = 173,696 + 5,280 = 178,976 hours.
Cost to Comply:
Reporting = $19,801,344
173,696 hours @ $114 an hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25))
Recordkeeping = $1,392,160
Labor (file/record clerk @ $17 an hour) 5,280 hours @ $17/hour = $89,760
Storage 176 respondents @ 8,000 sq. ft. × $925 (off-site storage) = $1,302,400
Total costs = $21,193,504
Labor $ ($19,801,344 + $89,760) + Recordkeeping Storage Costs ($1,302,400)

OMB's regulations require it to approve certain information collection requirements imposed by an agency rule. The Commission is submitting notification of this proposed rule to OMB. If the proposed requirements are adopted they will be mandatory requirements.

Title: FERC–516, Electric Rate Schedules and Tariff Filings; FERC–717 Standards for Business Practices and Communication Protocols for Public Utilities.

Action: Proposed Collections.

OMB Control Nos. 1902–0096 and 1902–0173.

Respondents: Business or other for profit.

Frequency of responses: On occasion.

Necessity of the Information:

489. The Federal Energy Regulatory Commission is proposing amendments to its regulations adopted in Order Nos. 888 and 889, and to the *pro forma* open access transmission tariff, to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. The purpose of this rulemaking is to strengthen the *pro forma* OATT to ensure that it achieves its original purpose—remedying undue discrimination—not to create new market structures. We propose to achieve this goal by increasing the clarity and transparency of the rules applicable to the planning and use of the transmission system and by addressing ambiguities and the lack of sufficient detail in several important areas of the *pro forma* OATT. The lack of specificity in the *pro forma* OATT creates opportunities for undue discrimination as well as making the undue discrimination that does occur more difficult to detect. To accomplish this we are proposing five objectives: (1) To improve transparency and

[440] 44 U.S.C. 3507(d) (2000).

[441] 5 CFR 1320.11 (2005).

[442] These burden estimates apply only to this NOPR and do not reflect upon all of FERC–516 or FERC–717.

consistency in several critical areas, by providing for greater consistency in the calculation of ATC, (2) to reform the transmission planning requirements of the *pro forma* OATT to eliminate potential undue discrimination and support the construction of adequate transmission facilities to meet the needs of all load-serving entities, (3) to remedy certain portions of the *pro forma* OATT that may have permitted utilities to discriminate against new merchant generation, including intermittent generation, (4) to provide for greater transparency in the provision of transmission service to allow transmission customers better access to information to make their resource procurement and investment decisions, as well as to increase the Commission's ability to detect any remaining incidents of undue discrimination, and (5) to reform and provide greater clarity in areas that have generated recurring disputes over the past 10 years, such as rollover rights, ''redirects,'' and generation redispatch. The reforms proposed in this NOPR are intended to address deficiencies in the *pro forma* OATT that have become apparent since the implementation of Order No. 888 in 1996 and to facilitate improved planning and operation of transmission facilities.

490. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov.*]

491. For submitting comments concerning the collections of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone (202) 395–4650, fax: (202) 395–7285. Due to security concerns, comments should be sent electronically to the following e-mail address: *oira_submission@omb.eop.gov.* Please reference the docket number of this rulemaking in your submission.

VII. Environmental Analysis

492. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[443] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications and services.[444]

VIII. Regulatory Flexibility Act Analysis

493. The Regulatory Flexibility Act of 1980 (RFA)[445] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. This rule applies to public utilities that own, control or operate interstate transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to modify their current OATTs by filing the revised *pro forma* OATT is 176.[446] Of these only six public utilities, or less than two percent, dispose of four million MWh or less per year.[447] The Commission does not consider this a substantial number, and in any event, these small entities may seek waiver of these requirements.[448] Moreover, the criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888 and 889. Thus, small entities who have received waiver of the requirements to have on file an open access tariff or to operate an OASIS would be unaffected by the requirements of this proposed rulemaking.

IX. Comment Procedures

494. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due August 7, 2006. Reply comments are due September 5, 2006. Comments must refer to Docket Nos. RM05–25–000 and RM05–17–000, and must include the commenters' name, the organization they represent, if applicable, and their address in their comments. Comments may be filed either in electronic or paper format.

495. To facilitate the Commission's review of the comments, commenters are requested to provide an executive summary of their position, not to exceed ten pages. Commenters are requested to identify each section of the NOPR that their discussion addresses and to use conforming headings. Additional issues the commenters wish to raise should be clearly identified in a separate section entitled ''Other Issues,'' which should be organized by the relevant *pro forma* OATT section (if applicable). Furthermore, we also request that commenters with specific tariff language suggestions submit a redline/strikeout version showing their proposed changes to the language that appears in the *pro forma* OATT attached to this NOPR.[449] The commenters should double space their comments. To assist commenters in their review, the Commission has posted a copy of the proposed revised *pro forma* OATT with changes from the current version of the *pro forma* OATT shown in redline/strikeout on the following location on our Web site at *http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp.*

496. Comments and reply comments may be filed electronically via the

[443] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[444] 18 CFR 380.4(a)(15) (2005).

[445] 5 U.S.C. 601–612 (2000).

[446] The sources for this figure are FERC Form No. 1 and FERC Form No. 1–F data.

[447] *Id.*

[448] The Regulatory Flexibility Act defines a ''small entity'' as ''one which is independently owned and operated and which is not dominant in its field of operation.'' *See* 5 U.S.C. 601(3) and 601(6)(2000); 15 U.S.C. 632(a)(1)(2000). In *Mid-Tex Elec. Coop.* v. *FERC*, 773 F.2d 327, 340–343 (D.C. Cir. 1985), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the Regulatory Flexibility Act, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to all public utilities. The revised *pro forma* OATT will apply only to those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

[449] The *pro forma* OATT includes two amendments that have been made since the tariff was finalized in Order No. 888–B. First, the tariff was amended to include protocols for curtailment of multi-system transactions and parallel flows. *See North American Reliability Council,* 85 FERC ¶ 61,353 (1998), *reh'g denied,* 87 FERC ¶ 61,161 (1999) and recently updated in *North American Electric Reliability Council,* 110 FERC ¶ 61,388 (2005). The second amendment incorporates standardized generator interconnection procedures. *See* Order No. 2003. The standardized generator interconnection procedures are not included in the *pro forma* OATT attached to this NOPR because we do not propose changes to them.

eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats and commenters may attach additional files with supporting information in certain other file formats. Documents created electronically using word processing software should be filed in the native application or print-to-PDF format and not in a scanned format. This will enhance document retrieval for both the Commission and the public. Attachments that exist only in paper form may be scanned. Commenters filing electronically should not make a paper filing. Service of rulemaking comments is not required. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE., Washington, DC 20426.

497. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

X. Document Availability

498. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

499. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type ''RM05–25'' or ''RM05–17'' in the docket number field.

500. User assistance is available for eLibrary and the Commission's website during normal business hours. For assistance, please contact the Commission's Online Support at 1–866–208–3676 (toll free) or 202–502–6652 (e-mail at *FERCOnlineSupport@FERC.gov*), or the Public Reference Room at 202–502–8371, TTY 202–502–8659 (e-mail at *public.referenceroom@ferc.gov*).

List of Subjects

18 CFR Part 35

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

18 CFR Part 37

Conflict of interests, Electric power plants, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission proposes to amend parts 35 and 37, Chapter I, Title 18 of the *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 71–7352.

2. Amend § 35.28 as follows:
a. paragraph (c) is revised.
b. paragraphs (d)(i) and d(ii) are redesignated as d(1) and d(2).
c. newly redesignated paragraph d(1) is revised.
d. paragraph (e)(1) (introductory text) is revised.
e. paragraph (e)(1)(ii) is revised.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) *Non-discriminatory open access transmission tariffs.*

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access *pro forma* tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____, or such other open access tariff as may be approved by the Commission consistent with Order No. ____, FERC Stats. & Regs. ¶ ____.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the *pro forma* tariff contained in Order No. 888, FERC Stats. & Regs. ¶31,036, as revised by the open access *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of ____, it must file the revisions to the *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____ pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA, no later than __.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce as of ____, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file no later than ____ the revisions to the *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

(iv) Any public utility whose transmission facilities are under the independent control of a Commission-approved ISO or RTO may satisfy its obligation under paragraph (c)(1) of this section, with respect to such facilities, through the open access transmission tariff filed by the ISO or RTO.

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the *pro forma* tariff required by this section.

(vi) Any public utility that seeks a deviation from the *pro forma* tariff contained in Order No. 888, FERC Stats. & Regs. ¶31,036, as revised in Order No. ____, FERC Stats. & Regs. ¶ ____, must demonstrate that the deviation is consistent with the principles of Order No., __ FERC Stats. & Regs. ¶ ____.

(vii) Each public utility's open access transmission tariff must include the standards incorporated by reference in part 38 of this chapter.

(2) Subject to the exceptions in paragraphs (c)(2)(i) and (c)(3)(iii) of this section, every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access tariff filed pursuant to this section.

(i) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(ii) [Reserved.]

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission *pro forma* tariff, which tariff must be the open access *pro forma* tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____, or such other open access tariff as may be approved by the Commission consistent with Order No. ____, FERC Stats. & Regs. ¶ ____.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after July 9, 1996, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide contained in Order No. ____, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA, no later than ____.

(iii) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must take transmission service under a joint pool-wide or system-wide *pro forma* tariff filed pursuant to this section for wholesale trades among the pool or system members.

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access *pro forma* tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____, or such other open access tariff as may be approved by the Commission consistent with Order No. ____, FERC Stats. & Regs. ¶ ____.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA, no later than ____.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the *pro forma* tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 no later than ____.

(d) *Waivers.* * * *

(1) No later than ____, or

* * * * *

(e) *Non-public utility procedures for tariff reciprocity compliance.* (1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036 and Order No. ____, FERC Stats. & Regs. ¶ ____.

(i) * * *

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 or 211A order should be granted.

* * * * *

PART 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEMS

3. The authority citation for part 37 continues to read as follows:

Authority: 16 U.S.C. 791–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

4. Amend § 37.6 as follows:
a. paragraph (a)(1) is revised.
b. paragraph (b)(introductory text) is revised.
c. paragraphs (b)(1)(v) through (b)(1)(viii) are added.
d. paragraphs (b)(2)(i) and b(2)(ii) are revised.
e. paragraph (b)(3) is revised.
f. paragraph (c)(2) is revised.
g. paragraphs (e)(1) and (e)(2)(ii) are revised.
h. paragraph (e)(3)(ii) is revised.
i. paragraphs (h) and (i) are added.

§ 37.6 Information to be posted on the OASIS.

(a) * * *

(1) Make requests for transmission services offered by Transmission Providers, Resellers and other providers of ancillary services, request the designation of a network resource, and request the termination of the designation of a network resource;

* * * * *

(b) *Posting transfer capability.* The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

(1) * * *

(v) *Available transfer capability* or *ATC* means the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses, or such definition as contained in Commission-approved Reliability Standards.

(vi) *Total transfer capability* or *TTC* means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards.

(vii) *Capacity Benefit Margin* or *CBM* means the amount of TTC preserved by the Transmission Provider for load-serving entities, whose loads are located on that Transmission Provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements, or such definition as contained in Commission-approved Reliability Standards.

(viii) *Transmission Reliability Margin* or *TRM* means the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure, or such definition as contained in Commission-approved Reliability Standards.

(2) * * *

(i) Information used to calculate any posting of ATC and TTC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on Commission-approved Reliability Standards as well as current industry practices, standards and criteria

(ii) On request, the Responsible Party must make all data used to calculate ATC, TTC, CBM, and TRM for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (*e.g.*, thermal, voltage, stability)) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. This information is to be retained for six months after the applicable posting period.

* * * * *

(3) *Posting.* The ATC, TTC, CBM, and TRM for all Posted Paths must be posted in megawatts by specific direction and in the manner prescribed in this subsection.

(i) *Constrained posted paths*—(A) *For Firm ATC and TTC. (1)* The posting shall show ATC, TTC, CBM, and TRM for a 30-day period. For this period postings shall be: By the hour, for the current hour and the 168 hours next following; and thereafter, by the day. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted daily for each period.

(*2*) Postings shall also be made by the month, showing for the current month and the 12 months next following.

(*3*) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following to the end of the planning horizon but not to exceed 10 years.

(B) *For Non-Firm ATC and TTC.* The posting shall show ATC, TTC, CBM and TRM for a 30-day period by the hour and days prescribed under paragraph (b)(3)(i)(A)(*1*) of this section and, if so requested, by the month and year as prescribed under paragraph (b)(3)(i)(A) (*2*) and (*3*) of this section. The posting of non-firm ATC and TTC shall show CBM as zero.

(C) *Updating Posted Information for Constrained Paths. (1)* The capability posted under paragraphs (b)(3)(i) (A) and (B) of this section must be updated when transactions are reserved or service ends or whenever the TTC estimate for the Path changes by more than 10 percent.

(*2*) All updating of hourly information shall be made on the hour.

(*3*) When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) are updated, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the update. This narrative should include, if relevant, scheduling of planned outages and occurrence of forced transmission outages, de-ratings of transmission facilities, scheduling of planned generation outages and occurrence of forced generation outages, changes in load forecast, changes in new facilities' in-service dates, or other events or assumption changes that caused the update.

(ii) *Unconstrained posted paths.* (A) Postings of firm and nonfirm ATC, TTC, CBM, and TRM shall be posted separately by the day, showing for the current day and the next six days following and thereafter, by the month for the 12 months next following. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted separately for the current day and the next six days following for each period. These postings are to be updated whenever the ATC changes by more than 20 percent of the Path's TTC.

(B) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following until the end of the planning horizon but not to exceed 10 years.

(iii) *Calculation of CBM.*

(A) The Transmission Provider must reevaluate its CBM needs at least quarterly.

(B) The Transmission Provider must post its practices for reevaluating its CBM needs.

(c) *Posting Transmission Service Products and Prices.*

(1) * * *

(2) Transmission Providers must provide a downloadable file of their complete tariffs in the same electronic format as the tariff that is filed with the Commission. Transmission Providers also must post all of their rules, standards and practices that relate to transmission services.

* * * * *

(e) *Posting specific transmission and ancillary service requests and responses*—(1) *General rules.* (i) All requests for transmission and ancillary service offered by Transmission Providers under the *pro forma* tariff, including requests for discounts, and all requests to designate or terminate a network resource, must be made on the OASIS and posted prior to the Transmission Provider responding to the request, except as discussed in paragraphs (e)(1) (ii) and (iii) of this section. The Transmission Provider must post all requests for transmission service, for ancillary service, and for the designation or termination of a network resource comparably. Requests for transmission service, ancillary service, and to designate and terminate a network resource, as well as the responses to such requests, must be conducted in accordance with the Transmission Provider's tariff, the Federal Power Act, and Commission regulations.

(ii) The requirement in paragraph (e)(1)(i) of this section, to post requests for transmission and ancillary service offered by Transmission Providers under the *pro forma* tariff, including requests for discounts, prior to the Transmission Provider responding to the request, does not apply to requests for next-hour service made during Phase I.

(iii) In the event that a discount is being requested for ancillary services that are not in support of basic transmission service provided by the Transmission Provider, such request need not be posted on the OASIS.

(iv) In processing a request for transmission or ancillary service, the Responsible Party shall post the same information as required in paragraphs (c)(4) and (d)(3) of this section, and the following information: the date and time when the request is made, its place in any queue, the status of that request, and the result (accepted, denied, withdrawn). In processing a request to designate or terminate the designation of a network resource, the Responsible Party shall post the date and time when the request is made.

(v) For any request to designate or terminate a network resource, the Transmission Provider (at the time when the request is received), must post on the OASIS (and make available for download) information describing the request (including: name of requestor, identification of the resource, effective time for the designation or termination, identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of the audit log required in § 37.7.

(vi) The Transmission Provider shall post a list of its current designated network resources and all network customers' current designated network resources on OASIS. The list of network resources should include the name of the resource, its geographic and electrical location, its total installed capacity, and the amount of capacity to be designated as a network resource.

(2) * * *

(ii) Information to support the reason for the denial, including the operating status of relevant facilities, must be maintained for five years and provided, upon request, to the potential Transmission Customer.

* * * * *

(3) *Posting when a transaction is curtailed or interrupted.* (ii) Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained and made available upon request, to the curtailed or interrupted customer, the Commission's Staff, and any other person who requests it, for five years.

* * * * *

(h) *Posting information summarizing the time to complete transmission service request studies.* (1) For each calendar quarter, the Responsible Party must post the set of measures detailed in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section related to the Responsible Party's processing of transmission service request system impact studies and facilities studies. The Responsible Party must calculate and post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section separately for requests for short-term firm point-to-point transmission service, long-term firm point-to-point transmission service, and requests to designate a new network resource and must be calculated and posted separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates. The Responsible Party is required to include in the calculations of the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section all studies the Responsible Party conducts of transmission service requests on another Transmission Provider's OASIS.

(i) *Process Time from Initial Service Request to Offer of System Impact Study Agreement.*

(A) Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service,

(B) Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party received the request for transmission service,

(C) Mean time (in days), for all requests acted on by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to when the Responsible Party changed the transmission service request status to indicate that the Responsible Party could offer transmission service or needed to perform a system impact study,

(D) Mean time (in days), for all system impact study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to the date when the Responsible Party delivered a system impact study agreement, and

(E) Number of new system impact study agreements executed during the reporting quarter.

(ii) *System Impact Study Processing Time.* (A) Number of system impact studies completed by the Responsible Party during the reporting quarter,

(B) Number of system impact studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed system impact study agreement,

(C) Mean time (in days), for all system impact studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed system impact study agreement to the date when the Responsible Party provided the system impact study to the entity who executed the system impact study agreement, and

(D) Mean cost of system impact studies completed by the Responsible Party during the reporting quarter.

(iii) *Transmission Service Requests Withdrawn from the System Impact Study Queue.* (A) Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter,

(B) Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter more than 60 days after the Responsible Party received the executed system impact study agreement, and

(C) Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter, from the date the Responsible Party received the executed system impact study agreement to date when request was withdrawn from the Responsible Party's system impact study queue.

(iv) *Process Time from Completed System Impact Study to Offer of Facilities Study.* (A) Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service,

(B) Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party completed the system impact study,

(C) Mean time (in days), for all facilities study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party completed the system impact study to the date when the Responsible Party delivered a facilities study agreement, and

(D) Number of new facilities study agreements executed during the reporting quarter.

(v) *Facilities Study Processing Time.* (A) Number of facilities studies completed by the Responsible Party during the reporting quarter,

(B) Number of facilities studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed facilities study agreement,

(C) Mean time (in days), for all facilities studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed facilities study agreement to the date when the Responsible Party provided the facilities study to the entity who executed the facilities study agreement,

(D) Mean cost of facilities studies completed by the Responsible Party during the reporting quarter, and

(E) Mean cost of upgrades recommended in facilities studies completed during the reporting quarter.

(vi) *Service Requests Withdrawn from Facilities Study Queue.*

(A) Number of transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter,

(B) Number of transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter more than 60 days after the Responsible Party received the executed facilities study agreement, and

(C) Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter, from the date the Responsible Party received the executed facilities study agreement to date when request was withdrawn from the Responsible Party's facilities study queue

(2) The Responsible Party is required to post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for three calendar years.

(3) The Responsible Party will be required to post on OASIS the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section in the event the Responsible Party, for two consecutive calendar quarters, completes more than twenty (20) percent of the studies associated with requests for transmission service from entities that are not Affiliates of the Responsible Party more than sixty (60) days after the Responsible Party delivers the appropriate study agreement. The Responsible Party will have to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section until it processes at least ninety (90) percent of all studies within 60 days after it has received the appropriate executed study agreement. For the purposes of calculating the percent of studies completed more than sixty (60) days after the Responsible Party delivers the appropriate study agreement, the Responsible Party should aggregate all system impact studies and facilities studies that it completes during the reporting quarter. The Responsible Party must calculate and post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section separately for requests for short-term firm point-to-point transmission service, long-term firm point-to-point transmission service, and requests to designate a new network resource and must be calculated and posted separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates.

(i) Mean, across all system impact studies the Responsible Party completes during the reporting quarter, of the employee-hours expended per system impact study the Responsible Party completes during reporting period;

(ii) Mean, across all facilities studies the Responsible Party completes during the reporting quarter, of the employee-hours expended per facilities study the Responsible Party completes during reporting period;

(iii) The number of employees the Responsible Party has assigned to process system impact studies;

(iv) The number of employees the Responsible Party has assigned to process facilities studies.

(4) The Responsible Party is required to post the measures in paragraph (h)(3)(a) through paragraph (h)(3)(d) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for five calendar years.

(i) *Posting data related to grants and denials of service.* The Responsible Party is required to post data each month listing, by path or flowgate, the number of transmission service requests that have been accepted and the number of transmission service requests that have been denied during the prior month. This posting must distinguish between the length of the service request (*e.g.*, short-term or long-term requests) and between the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The posted data must show:

(1) The number of non-Affiliate requests for transmission service that have been rejected,

(2) The total number of non-Affiliate requests for transmission service that have been made,

(3) The number of Affiliate requests for transmission service that have been rejected, and

(4) The total number of Affiliate requests for transmission service that have been made.

5. In § 37.7, paragraph (b) is revised to read as follows:

§ 37.7 Auditing Transmission Service Information.

* * * * *

(b) Audit data must remain available for download on the OASIS for 90 days, except ATC/TTC postings that must remain available for download on the OASIS for 20 days. The audit data are to be retained and made available upon request for download for five years from the date when they are first posted in the same electronic form as used when they originally were posted on the OASIS.

Note: The following appendices will not be published in the *Code of Federal Regulations*.

Appendix A: Commenter Acronyms

INITIAL COMMENTERS IN DOCKET NO. RM05–25–000

Abbreviation	RM05–25–000 Initial comments
AEP	American Electric Power System (AEP Texas North Company; AEP Texas Central Company; Appalachian Power Company; Columbus Southern Power Company; Indiana Michigan Power Company; Kentucky Power Company; Kingsport Power Company; Ohio Power Company; Public Service Company of Oklahoma; Southwestern Electric Power Company and Wheeling Power Company).
Alabama MEA	Alabama Municipal Electric Authority.
Alberta Intervenors	Alberta Intervenors (TransCanada Energy Ltd.; ENMAX Energy Marketing, Inc.; EPCOR Merchant and Capital, LP; and TransAlta Corporation).
Alberta System Operator	Alberta Electric System Operator.
Alcoa	Alcoa Inc. and Alcoa Power Generating Inc.
Alliance of State Leaders	Alliance of State Leaders Protecting Electricity Consumers.

[450] A "*" indicates that the commenter filed a notice of intervention only.

INITIAL COMMENTERS IN DOCKET NO. RM05–25–000—Continued

Abbreviation	RM05–25–000 Initial comments
Ameren	Ameren Services Company (Central Illinois Light Company d/b/a AmerenCILCO; Central Illinois Public Service Company d/b/a AmerenCIPS; Illinois Power Company d/b/a AmerenIP; Union Electric Company d/b/a AmerenUE; Ameren Energy Marketing Company; Ameren Energy Generating Company; and AmerenEnergy Resources Generating Company).
American Forest and Paper* [450]	American Forest and Paper Association.
American Transmission	American Transmission Company LLC.
AMP-Ohio	American Municipal Power-Ohio, Inc.
APPA	American Public Power Association.
APS	Arizona Public Service Company.
Arkansas Cities	Arkansas Cities and Cooperative (Conway Corporation; West Memphis Utilities Commission; City of Osceola, Arkansas; City of Prescott, Arkansas; Hope Water & Light Commission; and Farmers Electric Cooperative Cooperation).
Arkansas Commission	Arkansas Public Service Commission.
AWEA	American Wind Energy Association.
BC Transmission	British Columbia Transmission Corporation.
Bonneville	Bonneville Power Administration.
Bureau of Reclamation	U.S. Bureau of Reclamation.
CAISO	California Independent System Operator Corporation.
California Commission	Public Utilities Commission of the State of California.
Calpine	Calpine Corporation.
Canadian Electricity Association	Canadian Electricity Association.
Chelan	Public Utility District No. 1 of Chelan County and Public Utility District No. 2 of Grant County.
Cinergy	Cinergy Services, Inc. (Cincinatti Gas & Electric Company; PSI Energy, Inc.; and Union Light, Heat and Power Company).
Constellation	Constellation Energy Group, Inc.
Cottonwood	Cottonwood Energy Company LP and Union Power Partners, LP.
Detroit Edison	Detroit Edison Company.
Douglas	Public Utility District No. 1 of Douglas County.
Duke	Duke Energy Corporation.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Sam Rayburn Generation and Electric Cooperative, Inc.; and Tex-La Electric Cooperative of Texas, Inc.
Edison Mission	Edison Mission Energy, Edison Mission Marketing & Trading, Inc. and Midwest Generation EME, LLC.
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute and American Chemistry Council.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
Fayetteville	Public Works Commission of the City of Fayetteville, North Carolina.
FirstEnergy	FirstEnergy Service Company (FirstEnergy Solutions; American Transmission Systems, Inc.; Jersey Central Power and Light Company; Metropolitan Edison Company; and Pennsylvania Electric Company).
Florida Industrial Cogeneration Association	Florida Industrial Cogeneration Association.
FMPA	Florida Municipal Power Agency.
FP&L	Florida Power & Light Company.
Hogan	William H. Hogan.
HQ Energy	HQ Energy Services (U.S.), Inc.
IECG*	Industrial Energy Consumer Group.
Indicated New York Transmission Owners	Indicated New York Transmission Owners (Central Hudson Gas & Electric Corp.; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corp.; Orange and Rockland Utilities, Inc.; LIPA; New York Power Authority; and Rochester Gas and Electric Corp.).
International Transmission	International Transmission Company.
ISO New England	ISO New England, Inc. and New England Power Pool.
ISO/RTO	ISO/RTO Council.
KCP&L	Kansas City Power & Light Company.
Kentucky Commission	Kentucky Public Service Commission.
Lafayette	Lafayette Utilities System of the City and Parish of Lafayette, Louisiana; Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi; and Public Service Commission of the City of Yazoo City, Mississippi.
LDWP	City of Los Angeles Department of Water and Power.
LG&E	LG&E Energy LLC (Louisville Gas and Electric Company and Kentucky Utilities Company).
LPPC	Large Public Power Council.

INITIAL COMMENTERS IN DOCKET NO. RM05–25–000—Continued

Abbreviation	RM05–25–000 Initial comments
MEAG	MEAG Power.
Memphis Light	Memphis Light, Gas & Water Division.
Metropolitan Water District	Metropolitan Water District of Southern California.
MidAmerican	MidAmerican Energy Company.
Midwest Municipals	Midwest Municipal Transmission Group.
Midwest SATs	Midwest Stand-Alone Transmission Companies (American Transmission Company LLC; International Transmission Company; and Michigan Electric Transmission Company, LLC).
MISO	Midwest Independent Transmission System Operator, Inc.
MISO States	Organization of MISO States.
Montana Alberta Tie	Montana Alberta Tie Ltd.
NARUC	National Association of Regulatory Utility Commissioners.
National Grid	National Grid USA.
NCPA	Northern California Power Agency.
Nevada Commission	Public Utilities Commission of Nevada.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
New York Commission	New York State Public Service Commission.
North Carolina Commission	North Carolina Utilities Commission; Public Staff of the North Carolina Utilities Commission; and the Attorney General of the State of North Carolina.
Northeast Utilities	Northeast Utilities Service Company (Connecticut Light and Power Company; Western Massachusetts Electric Company; Public Service Company of New Hampshire; Holyoke Water Power Company; and Holyoke Power and Electric Company).
Northwest IPPs	Northwest Independent Power Producers Coalition (BP Energy; Calpine Corporation; EPCOR; National Energy Supply Company; Northwest Energy Development; Sempra Generation; Suez Energy North America, Inc.; and TransAlta Energy Marketing, (U.S.) Inc.).
Northwest Unregulated TUs	Northwest Unregulated Transmitting Utilities (Clark Public Utilities; Public Utility District No. 1 of Cowlitz County; Eugene Water and Electric Board; Public Utility District No. 2 of Grant County; Public Utility District No. 1 of Snohomish County; and Tacoma Power).
NorthWestern	NorthWestern Corporation.
NPPD	Nebraska Public Power District.
NRECA	National Rural Electric Cooperative Association.
Occidental	Occidental Chemical Corporation.
Ohio Commission	Public Utilities Commission of Ohio.
Oklahoma Commission	Oklahoma Corporation Commission.
Old Dominion	Old Dominion Electric Cooperative.
PacifiCorp	PacifiCorp.
PJM	PJM Interconnection, L.L.C.
PNM–TNMP	Public Service Company of New Mexico and Texas-New Mexico Power Company.
Portland General	Portland General Electric Company.
Powerex	Powerex Corp.
PPL	PPL Companies (PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Montana, LLC; PPL Holtwood, LLC; Lower Mount Bethel Energy, LLC; PPL Maine, LLC; PPL Great Works, LLC; PPL Colstrip I, LLC; PPL Colstrip II, LLC; PPL Martins Creek, LLC; PPL Brunner Island, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL Wallingford Energy, LLC; PPL Southwest Generation Holdings, LLC; PPL University Park, LLC, PPL Shoreham Energy, LLC; and PPL Edgewood Energy, LLC).
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Company d/b/a Progress Energy Carolinas and Florida Power Corporation, d/b/a Progress Energy Florida).
Public Power Council	Public Power Council.
Renewable Energy	Renewable Energy and Public Interest Organizations (American Wind Energy Association; Citizens for Pennsylvania's Future (PennFuture); Minnesotans for an Energy Efficient Economy; Natural Resources Defense Council; Ohio Consumers' Council; Pace Energy Project; Project for Sustainable FERC Energy Policy; Renewable Northwest Project; The Stella Group, Ltd.; The Wind Coalition; and West Wind Wires).
Rural Utilities Service	U.S. Department of Agriculture Rural Utilities Service.
Sacramento	Sacramento Municipal Utility District.
Salt River	Salt River Project Agricultural Improvement and Power District.
San Diego G&E	San Diego Gas & Electric Company.
Santa Clara	City of Santa Clara, California d/b/a Silicon Valley Power.
Santee Cooper	South Carolina Public Service Authority.
Sempra Global	Sempra Global.
SEPA	Southeastern Power Administration.

INITIAL COMMENTERS IN DOCKET NO. RM05–25–000—Continued

Abbreviation	RM05–25–000 Initial comments
Snohomish	Public Utility District No. 1 of Snohomish County, Washington.
South Carolina E&G	South Carolina Electric & Gas Company.
Southern	Southern Company Services, Inc.
Southern Montana Coop	Southern Montana Electric Generation and Transmission Cooperative, Inc.
Southwest TDU Group	Southwest Transmission Dependent Utility Group (Aguila Irrigation District; Ak-Chin Energy Services; Buckeye Water Conservation and Drainage District; Central Arizona Water Conservation District; Electrical District No. 3; Electrical District No. 4; Electrical District No. 5; Electrical District No. 6; Electrical District No. 7; Electrical District No. 8; Harquahala Valley Power District; Maricopa County Municipal Water District No. 1; McMullen Valley Water Conservation and Drainage District; City of Needles; Roosevelt Irrigation District; City of Safford; Tonopah Irrigation District; Wellton-Mohawk Irrigation and Drainage District).
Southwestern Coop	Southwestern Electric Cooperative, Inc.
SPP	Southwest Power Pool, Inc.
Steel Manufacturers Association	Steel Manufacturers Association.
Suez Energy NA	Suez Energy North America.
Tacoma	Tacoma Power.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
Tennessee Valley PPA	Tennessee Valley Public Power Association.
TransAlta	TransAlta Energy Marketing (U.S.) Inc.
Trans-Elect	Trans-Elect, Inc.
TVA	Tennessee Valley Authority.
WAPA	Western Area Power Administration.
Williams	Williams Power Company, Inc.
Wisconsin Commission	Public Service Commission of Wisconsin.
Wisconsin Electric	Wisconsin Electric Power Company.
Wyoming Infrastructure*	Wyoming Infrastructure Authority.
Xcel	Xcel Energy Services, Inc.

REPLY COMMENTERS IN DOCKET NO. RM05–25–000

Abbreviation	RM05–25–000 reply comments
Alberta Intervenors	Alberta Intervenors (TransCanada Energy Ltd.; ENMAX Energy Marketing, Inc.; EPCOR Merchant and Capital, LP; and TransAlta Corporation).
Anaheim	Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside, California.
APPA	American Public Power Association.
BC Transmission	British Columbia Transmission Corporation.
Bonneville	Bonneville Power Administration.
California Municipal Utilities Association	California Municipal Utilities Association.
Cogeneration Association of California	Cogeneration Association of California and Energy Producers and Users Coalition.
EEI	Edison Electric Institute.
ElectriCities	ElectriCities of North Carolina, Inc.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
Fallon	City of Fallon, Nevada.
Fertilizer Institute	Fertilizer Institute.
FMPA	Florida Municipal Power Agency.
FP&L	Florida Power & Light Company.
Great Northern	Great Northern Power Development, L.P.
Joint Commenters	Joint Commenters (Duke Energy. Corporation, Progress Energy Corporation, South Carolina Public Service Authority and Southern Company Services, Inc.).
Lafayette+ thnsp;451	Lafayette Utilities System of the City and Parish of Lafayette, Louisiana; Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi; and Public Service Commission of the City of Yazoo City, Mississippi.
LDWP	City of Los Angeles Department of Water and Power.
LPPC	Large Public Power Council.
Mark Lively+	Mark B. Lively.
MEAG	MEAG Power.
Memphis Light	Memphis Light, Gas & Water Division.

REPLY COMMENTERS IN DOCKET NO. RM05–25–000—Continued

Abbreviation	RM05–25–000 reply comments
Midwest Municipals	Midwest Municipal Transmission Group .
Midwest SATs	Midwest Stand-Alone Transmission Companies (American Transmission Company LLC; International Transmission Company; and Michigan Electric Transmission Company, LLC).
NARUC	National Association of Regulatory Utility Commissioners.
National Grid	National Grid USA.
NCPA	Northern California Power Agency.
Newmont Mining	Newmont USA Limited, d/b/a Newmont Mining Corporation.
Northwest IPPs	Northwest Independent Power Producers Coalition (BP Energy; Calpine Corporation; EPCOR; National Energy Systems Company; Northwest Energy Development; Sempra Generation; Suez Energy North America, Inc.; and TransAlta Energy Marketing, (U.S.) Inc.).
NRECA	National Rural Electric Cooperative Association.
Occidental	Occidental Chemical Corporation.
PacifiCorp	PacifiCorp.
Powerex	Powerex Corp.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Company d/b/a Progress Energy Carolinas and Florida Power Corporation, d/b/a Progress Energy Florida).
Puget	Puget Sound Energy, Inc.
Sacramento	Sacramento Municipal Utility District.
Salt River	Salt River Project Agricultural Improvement and Power District.
San Antonio	San Antonio City Public Service Board.
Seattle	City of Seattle—City Light Department.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern	Southern Company Services, Inc.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
Truckee Donner	Truckee Donner Public Utility District.
TVA	Tennessee Valley Authority.
TVA Noticing Distributors+	TVA Noticing Distributors (Paducah Power Systems, Glasgow Electric Plant Board, Princeton Electric Plant Board and Hopkinsville Electric System).
Williams	Williams Power Company, Inc.

COMMENTERS IN RM05–17–000

Abbreviation	RM05–17–000 Comments
Allegheny	Allegheny Power.
APPA	American Public Power Association.
Bonneville	Bonneville Power Administration.
CEOB	California Electricity Oversight Board.
EEI	Edison Electric Institute.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
FTC	Federal Trade Commission.
Generator Coalition	Generator Coalition (Cottonwood Energy Company LP; KGen Power Management Inc.; Suez Energy North America, Inc.; and Union Power Partners, LP).
International Transmission	International Transmission Company.
ISO/RTO	ISO/RTO Council.
LDWP	City of Los Angeles Department of Water and Power.
MidAmerican	MidAmerican Energy Company.
MISO	Midwest Independent Transmission System Operator, Inc.
NERC	North American Electric Reliability Council.
NY Commission	New York State Public Service Commission.
PG&E	Pacific Gas and Electric Company.
PGP	Public Generating Pool.
Powerex	Powerex Corp.
Southern	Southern Company Services, Inc.
Southern California Edison	Southern California Edison Company.*
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
WestConnect	WestConnect Public Utilities.

Pro Forma Open Access Transmission Tariff

Table of Contents

[451] A "+" indicates that the commenter also filed supplemental comments.

I. Common Service Provisions

1 Definitions

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.4 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 Commission

The Federal Energy Regulatory Commission.

1.6 Completed Application

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
2. Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
4. Provide sufficient generating capacity to maintain operating reserves

in accordance with Good Utility Practice.

1.8 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.12 Economy Energy

Energy purchased by a Network Integration Transmission customer that displaces that customer's own higher cost designated Network Resource(s) for the purpose of serving that customer's designated Network Load(s).

1.13 Eligible Customer

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.14 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.15 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.16 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.17 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.18 Load Ratio Share

Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III the Tariff and calculated on a rolling twelve month basis.

1.19 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.20 Long-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.21 Native Load Customers

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.22 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.23 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff.

1.24 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.25 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.26 Network Operating Committee

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration

Transmission Service under Part III of this Tariff.

1.27 Network Resource

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.28 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.29 Non-Firm Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.30 Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.31 Open Access Same-Time Information System (OASIS)

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.32 Part I

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.33 Part II

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Part III

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.35 Parties

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.36 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Transmission Service.

1.38 Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.39 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.40 Pre-Confirmed Application

An Application that commits the Transmission Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.41 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.42 Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.43 Reserved Capacity

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.44 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.45 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.46 Short-Term Firm Point-to-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.47 System Impact Study

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.50 Transmission Provider

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.51 Transmission Provider's Monthly Transmission System Peak

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.53 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to the longer of a competing request by any new Eligible Customer or five years and to pay the current just and reasonable rate, as approved by the Commission, for such service. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to [the acceptance by the Commission of the Transmission Provider's Attachment K], unless terminated, will become subject to the five year/one year requirement on the first rollover date after [the acceptance by the Commission of the Transmission Provider's Attachment K].

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible. The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) Any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control From Generation Sources Service

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service

Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service

Where applicable the rates and/or methodology are described in Schedule 6.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 CFR 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds

This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6. Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

The Transmission Provider will specify its Creditworthiness procedures in Attachment L.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

2. One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Federal Power Act

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-To-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term

The minimum term of Firm Point-To-Point Transmission Service shall be one hour and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, *i.e.*, in the chronological sequence in which each Transmission Customer has requested service. However, Pre-Confirmed Applications for service will receive priority over earlier-submitted requests that are not Pre-Confirmed. Within classes of requests (Pre-Confirmed or not confirmed), the highest price offered by the Eligible Customer is the first tiebreaker, followed by the date and time of the request.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Applications for Short-Term Point-To-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed. Within classes of requests (Pre-Confirmed or not confirmed), duration is the first tiebreaker, followed by the highest price offered by the Eligible Customer, followed by the date and time of the request.

(iii) If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one hour before the commencement of hourly service, one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after August 7, 2006 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission system. Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved.

13.8 Scheduling of Firm Point-To-Point Transmission Service

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *10 a.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Transmission customers may also batch requests and schedules for hourly firm service to be provided on the same day. Scheduling changes will be permitted up to *twenty (20) minutes* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to Pre-Confirmed Applications and second to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) Immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after August 7, 2006 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service

Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *2 p.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to *twenty (20) minutes* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (*e.g.*, hourly non-firm transactions will be Curtailed or

Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation To Provide Transmission Service That Requires Expansion or Modification of the Transmission System

If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to redispatch its own resources or expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify. To the extent a Transmission Provider cannot redispatch its own resources to provide the requested Firm Transmission Service, it shall identify generators in other control areas that could relieve the constraint and allow the Transmission Customer to seek redispatch with Transmission Providers in adjacent Control Areas.

15.5 Deferral of Service

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, *i.e.*, will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR ? 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transmission capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission

Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service

The Transmission Customer can obtain up to *five (5) one-year extensions* for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, *i.e.*, will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service

Requests for monthly service shall be submitted *no earlier than sixty (60) days* before service is to commence; requests for weekly service shall be submitted *no earlier than fourteen (14) days* before service is to commence, requests for daily service shall be submitted *no earlier than two (2) days* before service is to commence, and requests for hourly service shall be submitted *no earlier than noon the day* before service is to commence. Requests for service received *later than 2:00 p.m.* prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transfer Capability

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service *(i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.* [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, including an estimate of the number of hours of redispatch that may be required to accommodate the request for Transmission Service and a preliminary estimate of the cost of redispatch, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission

Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an ''Expedited Service Agreement'' pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Penalties for Failure To Meet Study Deadlines

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

20 Procedures if the Transmission Provider Is Unable To Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications on a Non-Firm Basis

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement (''Secondary Receipt and Delivery Points''), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification on a Firm Basis

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers that are Affiliates of the Transmission Provider shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion. Compensation to Resellers that are not Affiliates of the Transmission Provider shall be at rates established by agreement with the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service

In accordance with Section 4, Resellers may use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver Economy Energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary Service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to Secondary Service. Deliveries from resources other than

Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.

29 Initiating Service

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection), which shall include, for each Network Resource:

• Unit size and amount of capacity from that unit to be designated as Network Resource

• VAR capability (both leading and lagging) of all generators

• Operating restrictions

—Any periods of restricted operations throughout the year
—Maintenance schedules
—Minimum loading level of unit
—Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons

• Approximate variable generating cost ($/MWH) for redispatch computations

• Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource

• Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

(vi) Description of Eligible Customer's transmission system:

• Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider

• Operating restrictions needed for reliability

• Operating guides employed by system operators

• Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources

• Location of Network Resources described in subsection (v) above

• 10 year projection of system expansions or upgrades

• Transmission System maps that include any proposed expansions or upgrades

• Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to

Section 29.2(v) satisfy the following conditions: (1) The Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis; and

(ix) Any additional information required of the Transmission Customers as specified in the Transmission Provider's planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements To Be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) The Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider through OASIS as soon as reasonably practicable.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. The Network Customer may not schedule delivery of a Network Resource not physically interconnected with the Transmission Provider's Transmission System in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the Point of Delivery for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity.

30.5 Network Customer Redispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to

Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With the Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to [the effective date of a Final Rule in RM05–25–000], the Network Customer shall receive credit provided such facilities are integrated into the operations of the Transmission Provider's facilities and, if the transmission facilities were owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's Annual Transmission Revenue Requirement. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected With the Transmission Provider

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (*e.g.* the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, including an estimate of the number of hours of redispatch that may be required to accommodate the request for Transmission Service and a preliminary estimate of the cost of redispatch, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Penalties for Failure to Meet Study Deadlines

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

33 Load Shedding and Curtailments

33.1 Procedures

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

33.5 Allocation of Curtailments

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load

The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation Under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the [applicable regional reliability council], (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Schedule 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2

Reactive Supply and Voltage Control From Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may only charge a Transmission Customer for either hourly generator imbalances under Schedule 9 or hourly energy imbalances under this schedule for the same imbalance, but not both.

The Transmission Provider shall establish a deviation band of ±1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.

Schedule 5

Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6

Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7

Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $______/KW of Reserved Capacity per year.

(2) Monthly delivery: $______/KW of Reserved Capacity per month.

(3) Weekly delivery: $______/KW of Reserved Capacity per week.

(4) Daily delivery: $______/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Hourly delivery: $______/KW of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(6) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Schedule 8

Non-Firm Point-to-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $______/KW of Reserved Capacity per month.

(2) Weekly delivery: $______/KW of Reserved Capacity per week.

(3) Daily delivery: $______/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $______/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Schedule 9

Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may only charge a Transmission Customer for either hourly generator imbalances under this Schedule or hourly energy imbalances under Schedule 4 for the same imbalance, but not both.

The Transmission Provider shall establish a deviation band of +/-1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied on a net hourly basis to any Generator Imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). The charges for Generator Imbalance Service are set out below:

Attachment A—Form of Service Agreement for Firm Point-to-Point Transmission Service

1.0 This Service Agreement, dated as of ________________, is entered into, by and between ________________ (the Transmission Provider), and ________________ (''Transmission Customer'').

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:
Name______________ ________________
Title______________ __________________
Date______________ __________________

Transmission Customer:

By:
Name______________ ________________
Title______________ __________________
Date______________ __________________

Specifications for Long-Term Firm Point-to-Point Transmission Service

1.0 Term of Transaction: ________ ____
Start Date:______________ ____________
Termination Date:______________ ______

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:______________
Delivering Party:______________ ______

4.0 Point(s) of Delivery: ________ ____
Receiving Party:______________ ______

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):______________ ____________

6.0 Designation of party(ies) subject to reciprocal service obligation: __________

____

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service: __

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

____

____

____

____

____

____

____

____

Attachment B—Form of Service Agreement for Non-Firm Point-to-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

Name ________________________________

Title ________________________________

Date ________________________________

Transmission Customer:

By:

Name ________________________________

Title ________________________________

Date ________________________________

Attachment C—Methodology To Assess Available Transfer Capability

The Transmission Provider must include, at a minimum, the following information concerning its ATC calculation methodology:

(1) the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon);

(2) a process flow diagram that illustrates the various steps through which ATC/AFC is calculated; and

(3) a detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons.

(a) For TTC, a Transmission Provider shall: (i) Explain its definition of TTC; (ii) explain its TTC calculation methodology (*e.g.*, load flow, short circuit, stability, transfer studies); (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(b) For ETC, a transmission provider shall explain: (i) Its definition of ETC; (ii) the calculation methodology used to determine the transmission capacity to be set aside for native load, network load, and non-OATT customers (including, if applicable, an explanation of assumptions on the selection of generators that are modeled in service); (iii) how point-to-point transmission service requests are incorporated; (iv) how rollover rights are accounted for; and (v) its processes for ensuring that non-firm capacity is released properly (*e.g.*, when real time schedules replace the associated transmission service requests in its real-time calculations).

(c) If a Transmission Provider uses an AFC methodology to calculate ATC, it shall explain: (i) its definition of AFC; (ii) its AFC calculation methodology (*e.g.*, load flow, short circuit, stability, transfer studies); (iii) its process for converting AFC into ATC; (iv) what databases are used in its AFC assessments; (v) the assumptions used in its AFC assessments; and (vi) the reliability criteria used for contingency outages simulation.

(d) For TRM, a Transmission Provider shall explain: (i) Its definition of TRM; (ii) its TRM calculation methodology (*e.g.*, its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (iii) the databases used in its TRM assessments; (iv) the conditions under which the transmission provider uses TRM; and (v) the process used to prevent double-counting of contingency outages used in its TTC and TRM calculations. A Transmission Provider that does not reserve TRM must so state.

(e) For CBM, the Transmission Provider shall include a specific and self-contained narrative explanation of its CBM practice, including: (i) Who performs the assessment (transmission or merchant staff); (ii) the methodology used to perform generation reliability assessments (*e.g.*, probabilistic or deterministic); (iii) whether the assessment method reflects a specific regional practice; (iv) the assumptions used in those assessments; and (v) the basis for the selection of paths on which CBM is set aside.

(f) In addition, for CBM, a Transmission Provider shall: (i) Explain its definition of CBM; (ii) list the databases used in its CBM calculations; and (iii) prove that there is no double-counting of contingency outages when performing CBM, TTC, and TRM calculations.

(g) The Transmission Provider shall post its procedures for allowing CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). If the Transmission Provider's practice is not to reserve CBM, it shall so state.

Attachment D—Methodology for Completing a System Impact Study

To be filed by the Transmission Provider.

Attachment E—Index of Point-to-Point Transmission Service Customers

____

Customer:

____

Date of Service Agreement

____

Attachment F—Service Agreement for Network Integration Transmission Service

To be filed by the Transmission Provider.

Attachment G—Network Operating Agreement

To be filed by the Transmission Provider.

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be ________.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Attachment I—Index of Network Integration Transmission Service Customers

Customer

Date of Service Agreement

Attachment J—Procedures for Addressing Parallel Flows

To be filed by the Transmission Provider.

Attachment K—Transmission Planning Process

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following eight principles, as defined in the Final Rule in Docket No. RM05–25–000: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, and congestion studies.

Attachment L—Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit.

The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:

(1) A summary of the procedure for determining the level of secured and unsecured credit;

(2) A list of the acceptable types of collateral/security;

(3) A procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;

(4) A procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;

(5) A reasonable opportunity to contest determinations of credit levels or collateral requirements; and

(6) A reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

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