service there must be a default provider of these services. However, market-based rates for some of the ancillary services may be appropriate if the seller lacks market power for such services. Market power issues regarding ancillary services have to be addressed before market-based rates for ancillary services can be approved, as requested by AEP. We will consider market-based rates for ancillary services on a case-by-case basis.

In reply to Illinois Power, we agree that the transmission provider may incur incremental costs from its obligation to offer to provide ancillary services. We believe, however, these costs should be included in the price for those services. Order No. 888 requires the transmission provider to unbundle the cost of ancillary services from the base transmission rate. A rebundling of these costs with the base transmission rate, as Illinois Power requests, would not satisfy the unbundling requirement.

E. Real-Time Information Networks

In the Final Rule, the Commission concluded that in order to remedy undue discrimination in the provision of transmission services it is necessary to have non-discriminatory access to transmission information, and that an electronic information system and standards of conduct are necessary to meet this objective.[FN187] Therefore, in conjunction with the Final Rule, the Commission issued a final rule adding a new Part 37 that requires the creation of a basic OASIS and standards of conduct.

Rehearing Requests

Rehearing requests raising arguments with respect to specific aspects of OASIS and standards of conduct are addressed in Order No. 889-A, issued concurrently with this order.

F. Coordination Arrangements: Power Pools, Public Utility Holding Companies, Bilateral Coordination Arrangements, and Independent System Operators

In the Final Rule, the Commission explained that its requirement for non-discriminatory transmission access and pricing by public utilities, and its specific requirement that public utilities unbundle their transmission rates and take transmission service under their own tariffs, apply to all public utilities' wholesale sales and purchases of electric energy, including coordination transactions.[FN188] While the Commission "grandfathered" certain existing requirements agreements and non-economy energy coordination agreements, it also determined that certain existing wholesale coordination arrangements and agreements must be modified to ensure that they are not unduly discriminatory. The Commission then discussed (as set forth further below) how and when various types of coordination agreements will need to be modified, and when public utility parties to coordination agreements must begin to trade power under those agreements using transmission service obtained under the same open access transmission tariff available to non-parties.

The Commission explained that it was addressing four broad categories of coordination arrangements and accompanying agreements: "tight" power pools, "loose" power pools, public utility holding company arrangements, and bilateral coordination arrangements.

In addition, the Commission explained that ISOs may prove to be an effective means for accomplishing comparable access and, accordingly, provided guidance on minimum ISO characteristics.

1. Tight Power Pools

The Commission required public utilities that are members of a tight pool to file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) an individual Final Rule pro forma tariff; or (2) a joint pool-wide Final Rule pro forma tariff.[FN189] However, the Commission required them to file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and to begin to take service under that tariff for all pool transactions no later than December 31, 1996.[FN190] The Commission also required the public utility members of tight pools to file reformed power pooling agreements no later than December 31, 1996 if the agreements contain provisions that are unduly discriminatory or preferential.

If a reformed power pooling agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the Commission indicated that the pool may file a transmission tariff that contains an access fee (or file a higher transmission rate) for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs.

Rehearing Requests

Consumers Power asks the Commission to clarify that Order No. 888 does not preclude the Michigan Electric Coordinated Systems (MECS) from being in compliance by removing all transmission functions from pool control and allowing pool members or the pool to take transmission service from transmission-owning pool members under their open access tariffs. It asserts that this would be an interim placeholder alternative while retail deliberations continue in Michigan. Furthermore, as one of the two members of MECS, Consumers Power indicates that it would be willing to consider further modifications that would liberalize membership criteria during the transition period if the Commission otherwise clarifies that the MECS Pool is in compliance with Order No. 888. ***12312**

NY Municipals request that the Commission clarify that, particularly if generation services are to be provided at market-based rates, monopoly transmission services must continue to be provided at cost-based rates (raised in connection with the NYPP). They also ask that the Commission clarify that joint pool-wide tariffs must incorporate transmission rates that are uniform (non-pancaked) and strictly based on the embedded costs of the transmission facilities and related transmission expenses. Moreover, NY Municipals argue that transmission owners should receive a credit based on the depreciated costs of their transmission facilities.

TAPS also asks the Commission to clarify that pool-wide and system-wide tariffs must contain non-pancaked rates.

Commission Conclusion

While Consumers Power's proposal to remove transmission functions from pool control, if implemented in a non-discriminatory fashion, would satisfy the comparability requirements of Order No. 888, the Commission encourages Consumers Power to pursue a pool-wide tariff.[FN191]

NY Municipal Utilities' concern that rates for transmission service will not be priced at cost-based rates is ill-founded. While Order No. 888 does not establish any specific pricing methodology for tariff transmission service, the Commission expects all transmission rate proposals filed on compliance to be cost based and to meet the standard for conforming proposals set out in the Commission's Transmission Pricing Policy Statement. (See 18 CFR 2.22).

Regarding NY Municipal Utilities' and TAPS's requests for a uniform tariff with non-pancaked rates, Order No. 888 does not require a non-pancaked rate structure unless a non-pancaked rate structure is available to pool members. Although the Commission has encouraged the industry to reform transmission pricing, the Commission's current policy does not mandate a specific transmission rate structure.

With regard to NY Municipal Utilities' concern about market-based rates for generation, public utility owners of existing NYPP generation are not eligible to charge market-based power sales rates absent Commission approval. Order No. 888 allows market-based rates only if the seller in a case-specific filing demonstrates it meets the Commission's well-established criteria of showing that it and its affiliates do not have or have adequately mitigated transmission market power and generation market power, that there are no other barriers to entry, and there is no evidence of affiliate abuse or reciprocal dealing. With regard to requests to make market-based sales from new generation, the seller does not have to submit evidence of generation market power in long-run bulk power markets (subject to challenge where specific evidence can be presented);[FN192] however, for sales from existing generation at market-based rates, the applicant must demonstrate that it lacks, or has fully mitigated, generation market power.[FN193]

In response to NY Municipals' request that transmission owners that contribute transmission facilities to a power pool should receive a rate credit based on the depreciated costs of those transmission facilities, we agree that this is one possible way of reflecting a pool member's contributions or commitments of transmission facilities. However, NY Municipals has provided no rationale as to why we should limit the broader approach we adopted in Order No. 888 to this single mechanism.[FN194]

2. Loose Pools

In the Final Rule, the Commission found that public utilities within a loose pool must file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) an individual Final Rule pro forma tariff; or (2) a pool-wide Final Rule pro forma tariff.[FN195] However, the Commission required that they file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and begin to take service under that tariff for all pool transactions no later than December 31, 1996. [FN196] The Commission also required that the public utility members of loose pools file reformed power pooling agreements no later than December 31, 1996 if the agreements contain provisions that are unduly discriminatory or preferential. They also must file a joint pool-wide tariff no later than December 31, 1996.

If a reformed pooling agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the Commission determined that the pool may file a transmission tariff that contains an access fee (or a higher transmission rate) for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs.

Rehearing Requests

Union Electric asserts that the definition of loose pools is so vague that many public utilities, regional organizations and multi-lateral arrangements, which are not actually pools, may incorrectly be deemed loose pools by third parties. Thus, Union Electric asks the Commission to clarify that members or parties to multi-lateral arrangements only need to offer transmission services pursuant to their own individual company tariffs.

EEI asks the Commission to clarify the nature of the tariffs that loose pools may file to comply with the Rule to ensure that the members are not required to file tariffs for services that they do not now provide. EEI also requests that, where members of loose pools currently provide transmission services to each other, they may continue to provide such services to each other under each member's individual pro forma tariff in lieu of a pool-wide tariff (provided that those services are made available to all eligible entities on a non-discriminatory basis). Similarly, Montana Power argues that members of loose pools should be allowed to meet comparability by filing individual open access tariffs, without having to file a pool-wide tariff.[FN197]

Public Service Co of CO asserts that the primary purpose of the Inland Power Pool is to provide for reserve sharing during emergency conditions, although the pool agreement also allows for economy transactions. It argues that another way to comply with the Rule should be to eliminate the economy energy schedule of the Inland Power Pool Agreement. Moreover, Public Service Co of CO argues that given the number of non-jurisdictional entities within the Inland Power Pool, it may be impossible to agree on a pool-wide tariff. El Paso adds that Inland Power Pool should not be treated as a loose ***12313** pool because it functions as a reserve sharing mechanism and not as a pool.

Utilities For Improved Transition asks the Commission to clarify that pool members or members of other entities do not have to provide more transmission services than they already provide on a voluntary basis to each other. It contends that there is no record to support a broader obligation and would cause massive disruption and the disintegration of many existing pools. Utilities For Improved Transition maintains that pools should have substantial leeway to develop arrangements reflecting their diverse memberships and the diverse contributions made.

VEPCO seeks clarification whether the Commission intended to impose the single-system tariff requirement only with respect to multilateral agreements that provide for system-wide transmission rates for the parties to the agreements.

TAPS asks the Commission to clarify that section 35.28(c)(3) includes all pools and all holding company systems, as well as any multi-lateral agreement so long as the multi-lateral agreement explicitly or implicitly addresses transmission (e.g., by providing for a transaction without assessing transmission costs in connection with that transaction).

Commission Conclusion

In response to parties seeking clarification of the definition of a loose pool, the Commission clarifies that a loose pool is any multilateral arrangement, other than a tight power pool or a holding company arrangement, that explicitly or implicitly contains discounted and/or special transmission arrangements, that is, rates, terms, or conditions. The Commission requires public utilities that are members of a loose pool to either (1) reform their pooling arrangements in accordance with Order No. 888 or (2) excise all discounted and/or special arrangements transmission service from the pooling arrangement. That is, in the latter case the members could continue to provide other services (e.g., generation), but would cease to be a loose pool for purposes of Order No. 888.

The primary goal of Order No. 888's requirements for pooling arrangements, including "loose" pools, is to ensure comparability regarding transmission services that are offered on a pool-wide basis. We believe comparability for loose pools can be achieved if pooling agreements are modified: (1) to allow open membership and (2) to make the transmission service in the loose pool agreement available to others. While the Commission encourages pool-wide transmission tariffs that offer the full range of transmission services included in the pro forma tariff, we will not require, under the comparability principles of Order No. 888, that pool members offer to third parties transmission services that they do not provide to themselves on a pool-wide basis. For example, if existing loose pool members do not offer network services to each other, they do not have to expand the pool services to offer network services to themselves or any third parties. Additionally, we do not find it to be unduly discriminatory to provide some pool-wide transmission services to members under a pooling agreement and to provide other transmission services to members under the individual tariff of each member, as long as members and non-members have access to the same transmission services on a comparable basis and pay the same or a comparable rate for transmission.[FN198]

The Commission notes that the Inland Power Pool agreement provides for non-firm transmission service (Service Schedule D) for emergency service, scheduled outage service, and economy energy service. The Inland Power Pool agreement provides members preferential transmission rates for deliveries of emergency service, i.e., members will provide free non-firm transmission service at a higher priority than any other non-firm transactions. Such preferential service is not available to non-members. We consider any rates, terms or conditions of transmission service that favor members over non-members to be unduly discriminatory and preferential, whether embodied explicitly or implicitly in a loose pooling agreement. Pool members can either amend the agreement to provide comparable services to others and open the pool to new members, or amend the agreement to eliminate any preferential transmission availability and/or pricing.

In response to TAPS, the Commission agrees that Section 35.28(c)(3) applies to any pool, holding company system or multi-lateral agreement that contains explicit or implicit transmission rates, terms, or conditions.[FN199] For example, if a utility offers transmission without charge as part of such an agreement, it must offer transmission to all parties requesting a similar service either without charge or at an access fee or other transmission rate that comparably reflects transmission-related costs borne by members of the agreement.[FN200]

3. Public Utility Holding Companies

In the Final Rule, the Commission required that holding company public utility members, with the exception of the Central and South West (CSW) System, file a single system-wide Final Rule pro forma tariff permitting transmission service across the entire holding company system at a single price within 60 days of publication of the Final Rule in the Federal Register.[FN201]

With respect to CSW, the Commission directed the public utility subsidiaries of CSW to consult with the Texas, Arkansas, Oklahoma and Louisiana Commissions and to file not later than December 31, 1996 a system tariff that will provide comparable service to all wholesale users on the CSW System, regardless of whether they take transmission service wholly within ERCOT or the SPP, or take transmission service between the reliability councils over the North and East Interconnections.

The Commission gave public utilities that are members of holding companies an extension of the requirement to take service under the system tariff for wholesale trades between and among the public utility operating companies within the holding company system until December 31, 1996—the same extension it granted to power pools.[FN202] In addition, the Commission indicated that it may be necessary for registered holding companies to reform their holding company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff.

Rehearing Requests

FL Com asks the Commission to clarify whether it intends to require operating company members of a registered holding company to charge each other the same wheeling charge to be charged to others even though others pay nothing for transmission construction. FL Com argues that such ***12314** a charge would be inconsistent with the Commission's traditional treatment of public utility holding companies as a single entity.

AL Com asks the Commission to clarify that "intra-holding company transactions in support of economic dispatch across a single integrated system should not be subjected to additional transmission charges, while transactions between operating companies for the benefit of wholesale customers not included within the definition of native load customer require distinct transmission charges."[FN203]

Southern asks the Commission to clarify that transactions between public utility operating subsidiaries within a holding company system for the benefit of native load customers fall within the network service for which they are assigned cost responsibility under the Final Rule tariff.

AEP asserts that the Commission has provided no reason for requiring holding companies to use the pro forma tariff for intra-pool transactions. AEP asks the Commission to clarify whether the Rule applies to AEP. It asserts that the Preamble states that all members of holding company systems must use the pro forma tariff for intra-system transactions, but the regulatory text requires only a member of a public utility holding company "arrangement or agreement that contains transmission rates, terms or conditions * * *." AEP explains that the AEP System Interconnection Agreement and Transmission Agreement do not contain transmission rates, terms or conditions and the members do not offer transmission service to one another.

However, AEP argues that, if the Rule applies to AEP, Order No. 888 contains no explanation of why or how a different intra-pool allocation of transmission costs than would result from the pro forma tariff prejudices transmission users. It asserts that (1) AEP's allocation has been subject to extensive review over the last few years, (2) AEP treats itself as a single system, not as a collection of individual members, (3) each member carries its fair share of transmission costs, and (4) compliance with the Commission's requirement would be onerous. If the Commission does not remove this requirement, AEP requests waiver of the requirement.

Similarly, Allegheny Power asserts that its Power Supply Agreement (PSA) does not provide for "wholesale trades." It argues that the PSA is immaterial to all transmission services, including intra-company exchanges. Because the PSA is an existing contract that the Final Rule does not propose to abrogate, Allegheny Power asserts that the PSA need not be reformed under the Final Rule. Allegheny states that it will provide new wholesale service to itself and others under its open access tariff which was accepted for filing on December 6, 1995 in Docket No. ER96-58.

Union Electric assumes that the "rule is intended solely to mean that a holding company system would use the network integration part of the tariff, for its intra-system 'wholesale trades.' Indeed, if Union Electric and CIPS were required to take point-to-point service for their wholesale trades, they would be placed in an inferior and non-comparable position vis-a-vis customers on the Ameren tariff who will be entitled to single-system transmission service for a single or postage-stamp charge." (Union Electric notes that Union Electric and CIPS are currently seeking approval to merge, with the combined facilities being operated as the Ameren System.)

NU believes that Order No. 888 could be construed to require NU System Companies to charge each other as separate entities for transmission service in connection with intra-system cost allocations as if off-system wholesale sales had occurred. NU argues, however, that this is inconsistent with Commission precedent in treating the NU System Companies as a single integrated system and would give retail native load customers service inferior to that of wholesale native load (i.e., network) customers. NU further argues that it will result in duplicative transmission charges for energy flows between the NU System Companies. Moreover, NU asserts that viewing NU as a single system for establishing transmission rates, but as separate companies with respect to energy flows that result from economic dispatch of their generation to native load is inconsistent with the treatment of multistate non-holding company utilities and is thus discriminatory.

Blue Ridge seeks clarification that, to avoid double payment for transmission, "CSW must file its compliance filing resolving comparability issues and the appropriate CSW ERCOT transmission rate prior to September 1, 1996." Blue Ridge asserts that CSW must resolve a potential conflict between its rate structure and the new PUCT wheeling rule by September 1, 1996 (contemplated effective date for interim PUCT transmission rates).

Commission Conclusion

In requiring holding companies to file a pool-wide tariff, the Commission does not intend that transmission service provided by the operating subsidiaries to one another on behalf of their respective native loads be subjected to additional transmission charges. The Commission recognizes that the operating subsidiaries of a holding company bear cost responsibility for transmission facilities by virtue of ownership of such facilities. In many, if not all cases, transmission costs are equalized among operating subsidiaries through transmission equalization agreements (e.g., AEP's Transmission Agreement).

However, the Commission does intend, pursuant to Order No. 888, that holding company operating subsidiaries take transmission service under the same tariff rates, terms, and conditions as third-party customers that seek transmission service over the holding company system. This applies to all holding company systems that rely upon the transmission facilities of the individual operating subsidiaries to support central economic dispatch—including AEP and Allegheny. However, as suggested by Southern and Union Electric, the Commission anticipates that transmission service for an operating subsidiary's native load would be treated as network service under the pro forma tariff. Accordingly, the CP demands of each operating subsidiary's native load would establish each operating subsidiary's transmission cost responsibility related to network service over the integrated transmission facilities of the holding company system.

Thus, in response to the AL and FL Commissions, Southern, and NU, intra-holding company transactions in support of economic dispatch would not be subjected to "additional" transmission charges.[FN204] The load ratio pricing mechanism of the network portion of the tariff should ensure that each operating company bears its proportionate share of transmission costs without jeopardizing or otherwise penalizing these types of intra-system transactions. Moreover, any off-system sales would have to be taken under the point-to-point provisions of the tariff. As we noted in Order No. 888, "it may be necessary for registered holding companies to reform their holding ***12315** company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff."[FN205] However, nothing in Order No. 888 mandates any change to the method chosen for apportioning transmission revenues among the operating companies, which may be based, for example, upon equalizing transmission investment responsibility.

The concerns raised here by Blue Ridge are resolved on an interim basis because the PUCT has accepted the filing of CSW's Federal tariff as adequate in the Texas proceeding until differences between the Order No. 888 rate structure and the PUCT rate structure are resolved. If, CSW implements a new ERCOT transmission tariff in response to actions of the PUCT, then affected parties may bring any remaining concerns to the Commission's attention at that time through a section 206 complaint.

We note that the issue raised here by Blue Ridge is very similar to the one raised by Tex-La and East Texas Electric Cooperative, and addressed by the Commission's recent order, in Houston Lighting & Power Co., 77 FERC 61,113 at 61,439 (1996). There, the Commission found that it would be premature to address this issue at that time, and noted that parties would have an opportunity to raise their concerns after the PUCT finalizes its ERCOT tariff.

4. Bilateral Coordination Arrangements

In the Final Rule, the Commission required that any bilateral wholesale coordination agreements executed after the effective date of the Final Rule would be subject to the functional unbundling and open access requirements set forth in the Rule.[FN206] In addition, the Commission required that all bilateral economy energy coordination contracts executed before the effective date of the Rule be modified to require unbundling of any economy energy transaction occurring after December 31, 1996. Moreover, the Commission permitted all non-economy energy bilateral coordination contracts executed before the effective date of the Rule to continue in effect, but subject to section 206 complaints.

To compute the unbundled coordination compliance rate, the Commission indicated that the utility must subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. However, the Commission noted, if a utility's transmission operator offers a discounted transmission rate to the utility's wholesale marketing department or an affiliate for the purposes of coordination transactions, the same discounted rate must be offered to others for trades with any party to the coordination agreement. In addition, the Commission explained that discounts offered to non-affiliates must be on a basis that is not unduly discriminatory.

Rehearing Requests

SoCal Edison seeks clarification as to how Order No. 888 affects package agreements (i.e., bilateral contracts that provide some or all of requirements service, coordination service, or transmission service). In particular, SoCal Edison asks (1) what specific functions of each must be modified to comply with Order No. 888; (2) whether a sale of non-firm energy made pursuant to a package agreement must comply with the unbundling requirements for coordination contracts; (3) whether the requirement to remove preferential transmission access or pricing provisions applies to existing or future transmission services provided pursuant to package agreements; if so, what is the deadline; and (4) whether the rulings with respect to Mobile-Sierra apply to package agreements.[FN207]

APPA argues that the Commission should require all coordination arrangements to be subject to Order No. 888. CCEM asserts that to the extent non-economy energy coordination agreements are allowed to remain bundled, they should be identified in connection with determinations of available transfer capacity and, because they should only be a transitional matter, should be subject to a sunset date of December 31, 1996.

According to Utilities For Improved Transition, requiring the subtraction of the current tariff transmission rate from the current rate ceiling, without increasing the residual sales price, will force transmission providers to fail to recover their full costs of providing service because the Commission has previously prohibited these rates from including a transmission component (citing Green Mountain, 63 FERC 61,071 at 61,307-08 (1993) and Cleveland Electric, 63 FERC 61,244 at 62,277-78 (1993)).[FN208]

Union Electric also argues that the Commission should delete the requirement that the utility subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. According to Union Electric, actual bilateral economy sales do not include adders for recovery of transmission costs, but are typically limited to production or generation costs. Union Electric further asserts that the definition of economy energy coordination agreement is so open-ended, it may apply to many types of coordination transactions that are not mere energy economy sales. Union Electric argues that a split-the-savings charge cannot be unbundled in the manner described by the Commission because it is an incorrect assumption that the rate ceiling for every economy energy coordination sales agreement includes a transmission cost component. If Union Electric is required to arbitrarily subtract a transmission charge for its economy sales, it argues that it will be penalized. At a minimum, it argues, a utility should be permitted to submit a list of economy coordination rate schedules that it believes to be already unbundled and should not have to subtract a transmission charge. Alternatively, it argues that the Commission should not require unbundling unless the Commission determines that the existing rate ceiling has been cost justified on a basis that includes an allowance for the full recovery of transmission function cost.[FN209]

Commission Conclusion

SoCal Edison represents that its package agreements include requirements services as well as coordination services. For existing bilateral economy energy coordination agreements, Order No. 888, as clarified by the Commission's May 17 Order, requires the unbundling of transmission from generation for all such contracts on or before December 31, 1996.[FN210] Thus, any economy energy service included in existing package agreements must be unbundled.

Regarding non-firm energy sales made under a package agreement, SoCal Edison provides no information distinguishing that service from other ***12316** economy energy coordination transactions, which include all "if, as and when available" services (see section 35.28(b)(2)). Absent more information, non-firm energy sales should be unbundled.

We further note that our requirements concerning unbundling of bilateral coordination arrangements apply regardless of whether such arrangements are governed by the public interest or just and reasonable standard of review.

With respect to APPA's concerns, the Final Rule provides that all bilateral economy energy coordination contracts executed before the effective date of the Final Rule must be modified to require unbundling of any economy energy transaction occurring after December 31, 1996. Non-economy energy bilateral coordination contracts executed before the effective date of the Final Rule, however, were allowed to continue in effect, but subject to complaints filed under section 206 of the FPA.[FN211] We drew this distinction for both policy and practical reasons. The ability to use discounts on transmission in order to favor short-term economy energy sales made out of the transmission provider's own generation was of particular concern to the Commission. Thus, in order to eliminate the ability of transmission providers to exercise undue discrimination for short-term coordination transactions under existing umbrella-type agreements, we required unbundling by December 31, 1996.[FN212] However, non-economy energy coordination agreements presented a different situation.

In the Final Rule, we expressed a particular concern with not abrogating non-economy energy coordination agreements, which we indicated may reflect complementary long-term obligations among the parties.[FN213] Non-economy energy coordination agreements consist for the most part of long-term reliability arrangements. Providing for the abrogation of these arrangements could cause special problems for the reliable operation of the grid. Examples include agreements governing sales during emergency or maintenance periods. These agreements, unlike economy energy agreements where trade is on an "as, if and when available" basis, often have specified terms governing the parties' responsibilities. As a result, many non-economy energy coordination agreements are more akin to requirements contracts than to economy energy coordination agreements. Therefore, we determined to permit this category of contracts to run their course, absent a case specific complaint. The burden would be on the complainant to demonstrate that the transmission component of a non-economy energy coordination agreement is unduly discriminatory or otherwise unlawful. The Commission would decide based on the facts of the case whether unbundling is the appropriate remedy. Neither CCEM nor APPA have presented evidence or convincing arguments as to why these types of agreements should be unbundled generically.[FN214]

The Commission affirms the requirement in Order No. 888 that the transmission rate for any economy energy coordination service be unbundled. The Commission states in Order No. 888 that to adequately remedy undue discrimination, public utilities must remove preferential transmission access and pricing provisions from agreements governing their transactions.[FN215] In the cases cited by Utilities For Improved Transition, the Commission prohibited the utility from charging a split-savings rate plus a contribution to fixed costs. The Commission has long allowed utilities to set their coordination rates by reference to their own costs (cost-based ceilings) or by dividing the pool of benefits (fuel cost differentials) brought about by the transaction. [FN216] Utilities have been free to design a rate using either method but not both. Regardless of the method adopted to set a bundled rate on file (a seller's own costs or a sharing of transaction benefits), a bundled rate constitutes the total charge for all components and must now be unbundled.

A split-savings rate is set without reference to the seller's fixed costs and, therefore, Union Electric's argument is not germane. We are not requiring that the present rate be adjusted upward or downward. Rather, we are requiring disassembly of the existing rate into component parts one of which represents the rate being charged for transmission service. If a utility is no longer satisfied that an existing rate is compensatory, with regard to either the generation component or the transmission component, it may file an appropriate revision under section 205.

ISO Principles

In the Final Rule, the Commission set out certain principles that will be used in assessing ISO proposals that may be submitted to the Commission in the future.[FN217] The Commission emphasized that these principles are applicable only to ISOs that would be control area operators, including any ISO established in the restructuring of power pools.

The Commission set forth the following principles for ISOs:

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic ***12317** information network consistent with the Commission's requirements.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

11. An ISO should establish an alternative dispute resolution (ADR) process to resolve disputes in the first instance.

Rehearing Requests

General Comments

NY Municipal Utilities argue that if the NYPP participants (or other tight pools) elect to establish an ISO, the ISO Principles should be made mandatory for the protection of transmission dependent utilities.

NY Com asks the Commission to clarify that it will allow flexibility to states and utilities in structuring proposals that meet the goals underlying the ISO principles. It explains that the parties to New York's electric competition proceeding are discussing the formation of an ISO in which transmission owners control the system operator, but would have to divest their competitive generation. NY Com further notes that it has not decided that matter yet, but it does not want to see such options foreclosed.

Minnesota P&L argues that certain functions, particularly those involving local area circumstances and safety, are better handled at the local level. It further argues that control area responsibilities of an ISO should focus on regional issues and operations, and on establishing and enforcing uniform criteria and guidelines for local control area operations in order to assure non-discriminatory treatment of all transmission customers.

AMP-Ohio asserts that the Commission should require the separation of transmission, generation and distribution through an ISO and, at a minimum, the Commission should include a Stage 3 of implementation to bring ISOs to reality.

ISO Principle 1

NYPP argues that the Commission should not include a rigid ban on transmission owner leadership in ISO governance because it is the transmission owner that is ultimately responsible for the reliability of the bulk power system.[FN218]

ISO Principle 2

NYPP asks that the Commission revise this principle to take a more flexible approach to significant employee issues. NYPP explains that it has 81 management employees on the payroll of individual member systems and that pension rights (accrual rights based on an average salary) and medical insurance (preexisting conditions) are through the individual member systems.

ISO Principle 3

SoCal Edison asks that this principle be revised to permit a separate access charge for each utility in order to avoid cost shifting. Anaheim seeks revision of this principle to require that an ISO provide comparable compensation to all transmission owners that make transmission facilities available for use by the ISO.

ISO Principle 5

Anaheim asks that this principle be revised to make clear that ISO arrangements should seek to encourage participation by all transmission owners within the region.

ISO Principle 6

NYPP seeks clarification that an ISO needs control over more than some generation facilities because the more generating facilities operating under an ISO the more reliability there is. Thus, it asserts that the Commission should clarify that its description of ISO control of generation does not require only a minimalist approach to ISO generation control.

ISO Principle 8

SoCal Edison seeks revision of this principle to remove the language linking the ISO to performing studies necessary to identify appropriate grid expansions. According to SoCal Edison, an ISO should not be a project sponsor or should not conduct planning studies to determine what facilities should be constructed because those actions would compromise its independence.

In addition, SoCal Edison seeks revision of this principle to permit a transmission usage charge that incorporates locational marginal cost pricing for managing transmission congestion.

Commission Conclusion

We reaffirm our strong commitment to the concept of ISOs, and to the ISO principles described in Order No. 888. We continue to believe that properly structured ISOs can be an effective way to comply with the comparability requirements of open access transmission service. Nevertheless, we do not believe at this time that it is appropriate to require public utilities or power pools to establish ISOs, as suggested by AMP-Ohio. We think it is appropriate to permit some time to confirm whether functional unbundling will remedy undue discrimination before reconsidering our decision that ISO formation should be voluntary.

A number of the above rehearing requests on ISOs are from New York parties and deal with ongoing efforts in New York that would reform the New York Power Pool pooling agreements, restructure power markets, and possibly form an ISO. Some of these arguments are in apparent conflict; for example, the NY Municipal Utilities argue that the 11 ISO principles should be made mandatory if the New York Power Pool participants elect to establish an ISO, while the NY Com argues that the Commission should clarify Order No. 888 to state that it will allow flexibility to states and utilities in structuring proposals that meet the goals underlying the ISO principles. We note that since the time the rehearing requests were filed, the NY Power Pool has filed amendments to its pooling agreements on December 30, 1996 and also has filed, on January 31, 1997, various agreements and tariffs designed to implement an ISO and market exchange. To the extent the rehearing requests from New York parties deal with matters that have been filed with the Commission subsequent to the rehearing requests, the Commission will address the issues raised in the context of those filings.

In response to NY Com's request for clarification that we provide flexibility to states and their utilities in structuring ISO proposals, the Commission at this time clearly cannot, and does not intend to, prescribe a "cookie cutter" approach to ISOs. However, the Commission does believe that certain basic principles must be met to ensure non-discriminatory transmission services. We reaffirm our view that ISO Principles 1 (independence with respect to governance) and 2 (independence with respect to financial interests) are fundamental to ensuring that an ISO is truly independent and would not favor any class of transmission users. As the Commission stated in its recent order on the proposed PJM ISO:

The principle of independence is the bedrock upon which the ISO must be built if stakeholders are to have confidence that it ***12318** will function in a manner consistent with this Commission's pro-competitive goals.[FN[219]]

ISO governance that is disproportionately influenced by transmission owners, unless they have fully divested their interests in generation, is not consistent with ISO Principle 1. We remain concerned that ISO proposals that do not include governance by a fair representation of all system users may not be independent, although we reserve final judgment on any specific governance structure until we have an opportunity to review a specific proposal.[FN220]

In response to the argument made by NYPP that transmission owner leadership in ISO governance may be needed because transmission owners are ultimately responsible for the reliability of the bulk power system, we emphasize that reliability is of primary importance to this Commission and that the formation and operation of an ISO should not in any way impair reliability. We believe that one of the main purposes of an ISO is to make an independent party, the ISO, responsible for at least short-term reliability. Even if both the transmission owners and the ISO will be responsible for some aspects of reliability, this does not affect our finding that the governance of the ISO must be independent of the transmission owners so that the ISO can carry out its own responsibilities in a not-unduly discriminatory manner.

In response to arguments of the NYPP that the Commission should revise Principle 2 to take a more flexible approach to employee issues, we reaffirm the necessity of requiring the employees of an ISO to be financially independent of market participants and note that Principle 2 suggests that a short transition period should be adequate for ISO employees to sever all financial ties with former transmission owners. We recognize that some flexibility may be necessary regarding the length of a transition period, but believe that ISO employees must in fairly short order be independent of all financial ties to any market participants, if we are to achieve not unduly discriminatory practices in generation and transmission markets.

A number of additional parties seek other revisions to or clarifications of the ISO Principles. For example, Minnesota P&L requests clarification or rehearing to ensure that the Commission provides sufficient flexibility to permit local operators, under the general supervision and control of the ISO, to perform local operational functions, such as performing switching operations. In response to this concern, we note that Principle 3 (open access under a single tariff) says that the portion of the transmission grid operated by a single ISO should be as large as possible. Our view, as described above, is that an ISO, which includes all affected users, should be responsible for operation of the system and ensuring reliability. The ISO may use some combination of actual physical control over facilities and virtual control of facilities by others (i.e., the ISO exercises control over facilities by instructing the transmission owners' or generation owners' staffs as to the actions to be taken). The broad range of interested parties that establish the ISO must determine what services the ISO will perform and what services transmission owners or others will perform under ISO supervision.

We deny the requests by Socal Edison and Anaheim to revise ISO Principle 3 to permit separate access charges for each utility to avoid cost shifting. We think ISO Principle 3 already provides sufficient flexibility to accommodate the concerns of these parties with respect to design of access charges and compensation to owners for transmission facilities under operational control of the ISO.

Similarly, we see no reason to revise Principle 5 (control of interconnected operations) as requested by Anaheim. We agree with Anaheim that wide participation of transmission owners in a region will help ensure open access and increase efficient transmission coordination. ISO Principle 3 says that the portion of the transmission grid operated by a single ISO should be as large as possible. ISO Principle 5 says that an ISO should have control over the operation of interconnected transmission facilities within its region. These principles, as written, address Anaheim's concern.

With respect to NYPP's request for clarification of ISO Principle 6 (dealing with constraints), we note that the description of ISO Principle 6 in the Final Rule says that the ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system.[FN221] We do not think it is appropriate for the Commission to give further generic guidance now on what constitutes the proper level of operational control over generation. The ISO, including all stakeholders, needs to address this issue, based on the structure of power markets and perhaps other local considerations, in preparing a specific proposal for our approval.

Finally, we deny SoCal Edison's request for revision of ISO Principle 8 (pricing). In response to SoCal Edison's concern, ISO Principle 8 allows the use of appropriate locational marginal cost pricing. The principle allows flexibility regarding which regional organization of market participants (ISO or RTG) conducts the necessary studies to identify the need for expansion. We are unpersuaded by SoCal Edison's arguments that the fact that an ISO is involved in planning for transmission facility expansion would in any way compromise the independence of the ISO.

G. Pro Forma Tariff

In the Final Rule, the Commission combined the requirements for point-to-point transmission service and network transmission service into a single pro forma tariff.[FN222] The Commission explained that this eliminates many of the differences between the two NOPR pro forma tariffs, provides a unified set of definitions, and consolidates certain common requirements such as the obligation to provide ancillary services. The Commission also noted that it was issuing an accompanying Notice of Proposed Rulemaking in Docket No. RM96-11-000 in which it was seeking comments on whether a different form of open access tariff —one based solely on a capacity reservation system—might better accommodate competitive changes occurring in the industry while ensuring that all wholesale transmission service is provided in a fair and non-discriminatory manner.[FN223]

1. Tariff Provisions That Affect The Pricing Mechanism

a. Non-Price Terms and Conditions
In the Final Rule, the Commission explained that the Final Rule pro forma tariff is intended to initiate open access, with non-price terms and conditions based on the contract path model of power flows and embedded cost ratemaking.[FN224] It emphasized that the Final Rule pro forma tariff is not intended to signal a preference for contract path/embedded cost pricing for the future. The Commission indicated ***12319** that it will in the future entertain non-discriminatory tariff innovations to accommodate new pricing proposals.

The Commission further indicated that, by initially requiring a standardized tariff, it intends to foster broad access across multiple systems under standardized terms and conditions. However, the Commission emphasized that the tariff provides for certain deviations where it can be demonstrated that unique practices in a geographic region require modifications to the Final Rule pro forma tariff provisions.

Finally, the Commission stated that it will allow utilities to propose a single cost allocation method for network and point-to-point transmission services.

b. Network and Point-to-Point Customers' Uses of the System (so called "Headroom")
In the Final Rule, the Commission explained that it will not allow network customers to make off-system sales within the load-ratio transmission entitlement at no additional charge.[FN225] The Commission further explained that use of transmission by network customers for non-firm economy purchases, which are used to displace designated network resources, must be accorded a higher priority than non-firm point-to-point service and secondary point-to-point service under the tariff. In addition, the Commission found that off-system sales transactions, which are sales other than those to serve the transmission provider's native load or a network customer's load, must be made using point-to-point service on either a firm or non-firm basis. In rejecting the "headroom" concept (where a network customer can make off-system sales as long as its total use of the system does not exceed its coincident peak demand), the Commission explained that it was not requiring any utility to take network service to integrate resources and loads and if any transmission user (including the public utility) prefers to take flexible point-to-point service,[FN226] they are free to do so. Further, the Commission explained that any point-to-point customer may take advantage of the secondary, non-firm flexibility provided under point-to-point service equally, on an as-available basis.

Rehearing Requests
A number of entities argue that it is unreasonable to permit firm point-to-point customers to receive non-firm service, up to their contract demand, at no additional charge, at secondary receipt and delivery points, but to require transmission providers and network customers to purchase transmission for all off-system sales, including non-firm sales made in competition with sales made by the point-to-point customer.[FN227] FPL asserts that having built and paid for the entire transmission network, the owner and the network customer should have the flexibility to use the network as they need. Utilities For Improved Transition declare that just as the firm point-to-point customer is permitted to maximize the use of its contract demand, the transmission provider and network customer should be entitled to maximize their long-term fixed cost obligation (citing AES Power, Inc., 69 FERC 61,345 at 62,300 (1994) (AES) for the proposition that the utility and its native load customers are obligated to pay all the costs of the transmission system without regard to the amount of energy actually scheduled).

FPL and Carolina P&L suggest two possible solutions: (1) allow the transmission provider and network customer to have rights to the headroom beneath their fixed cost obligations at no additional charge, or (2) restrict the no-charge use of firm point-to-point headroom to transmission service associated with non-firm purchases to serve load. Under either of these options, they assert, the firm point-to-point customer's rights to make non-firm off-system sales would be on an even competitive footing with the transmission provider or network customer.

PA Coops maintain that network customers should have the right to reassign/sell unused capacity below their 12-month rolling average peak demand at no additional charge. Cajun argues that network customers should be allowed to use the transmission system for non-firm (and perhaps firm) coordination transactions at no additional cost, provided the network customer's total use of the transmission system does not exceed its load ratio share. Cajun notes that the Commission seems to have determined elsewhere in the Rule that a network customer has already paid for the full use of its load ratio share (citing mimeo at 332 and 338). In addition, Cajun states that requiring the network customer to use point-to-point service results in the network customer paying twice for the same capacity.

VT DPS argues that the Commission should permit network users to make limited use of their network capacity to make off-peak off-system sales. It asserts that UtiliCorp's network tariff, filed in Docket No. ER95-203, provides a useful model: "the level of capacity utilized by the company or the customer for its combined network load and off-system sales load would be fixed by the tariff as the highest coincident peak load experienced by the transmitting utility in the three years preceding the off-system sale." According to VT DPS, this places all firm users on a par. In contrast, VT DPS argues that the Commission's solution is arbitrary and patently inadequate. VT DPS claims that concerned parties are not just transmission providers, but include state agencies and entities that need to take network service. VT DPS further argues that the lower priority for secondary service under the point-to-point tariff may pose an unacceptable risk to public utilities with firm obligations to serve their load, and having to agree to a fixed demand quantity may be unsatisfactory for public utilities with growing customer loads and a statutory obligation to serve those loads.

LEPA argues that:

[t]he Commission erred in not finding that in order to compete, one must be able to utilize base load units of 500MW size because entry without the ability to employ such base load units would make the putative entrant unable to compete; that in order to employ such units, or portions of them, the entrant had to engage in the coordinated development of base load units; that such coordinated development requires use of transmission for that purpose so as to be able to sell portions of the output of a baseload unit off-system, and that without 'headroom,' the cost of transmission for that purpose would not be comparable with the cost of transmission for the same purpose of the owner of the transmission. (LEPA at 5).

Commission Conclusion

The requests for rehearing on this issue present no arguments that were not fully considered in Order No. 888. Petitioners continue to claim that transmission providers and network customers are competitively disadvantaged vis-a-vis point-to-point transmission customers due to the point-to-point customers' ability to use as available, non-firm service over secondary points of receipt and delivery at no additional cost. The Commission attempted to strike a balance on this issue in Order No. 888 by allowing both network and point-to-point services to be priced on the same basis (i.e., no longer summarily rejecting the use of the average of the 12 monthly system ***12320** peaks as the denominator for the rate for point-to-point service). Additionally, the Commission established a lower priority for the non-firm secondary point-to-point service than for either economy purchases by network customers or for stand-alone non-firm point-to-point service, as discussed in Section IV.G.3.b. Accordingly, we believe that these concerns have been sufficiently addressed.

Furthermore, these entities want to be allowed to make off-system sales under their network service at no additional charge as long as their total use of the system does not exceed their load ratio share. They claim that it is inequitable not to allow such "headroom" sales under the network service while allowing firm point-to-point customers to use non-firm transmission service up to their contract demands using secondary receipt and delivery points at no additional charge. As the Commission stated in Order No. 888, customers are not obligated to take network transmission service.[FN228] If customers want to take advantage of the as-available, non-firm service over secondary points of receipt and delivery through the point-to-point service, they may elect to take firm point-to-point transmission service in lieu of the network service. We further note that transmission providers must take point-to-point transmission service for their own off-system sales, which results in comparable treatment for both the transmission provider and network customers. Transmission providers and other customers taking point-to-point transmission service do not need to be allowed to make "headroom" sales because they have access to as-available, non-firm service over secondary points of receipt and delivery at no additional charge through their point-to-point service.

Cajun's argument that a network customer has already paid for the full use of its load-ratio share of the system ignores the fact that network service is based on integrating a network customer's resources with its load, not on making off-system sales. This is why network customers pay for service on a load-ratio basis. If Cajun is concerned that it may need to pay for both network service and point-to-point service, Cajun can simply elect to take point-to-point service for all of its transmission needs.

VT DPS' claim that the lower priority accorded to transmission service to secondary points of receipt and delivery under flexible point-to-point service would present an "unacceptable risk" to public utilities is unsubstantiated. If the risk of having this secondary service curtailed is too great, this customer has the option to: (1) take stand-alone non-firm point-to-point service (which has a higher priority), (2) take this service on a firm point-to-point basis, or (3) take network service, which has a higher priority for economy purchases than either stand-alone non-firm or secondary non-firm point-to-point service.

With respect to LEPA's argument, the Commission has the goal of encouraging competition in the generation market, not discouraging generation competition by erecting barriers to entry such as arbitrary generator size. Furthermore, LEPA's argument that comparability is not achieved without allowing headroom is incorrect because both network customers as well as the transmission provider must obtain point-to-point transmission service to accommodate transmission for wholesale sales.

c. Load Ratio Sharing Allocation Mechanism for Network Service

In the Final Rule, the Commission concluded that the load ratio allocation method of pricing network service continues to be reasonable for purposes of initiating open access transmission.[FN229] The Commission also reaffirmed the use of a twelve monthly coincident peak (12 CP) allocation method because it believed the majority of utilities plan their systems to meet their twelve monthly peaks. However, the Commission stated that it would allow utilities to file another method (e.g., annual system peak) if they demonstrate that it reflects their transmission system planning.

With respect to concerns raised about pancaked rates for network service provided to load served by more than one network service provider, the Commission indicated that if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so. However, customers that elect to do so, the Commission explained, must seek alternative transmission service for any such load that has not been designated as network load for network service. The Commission indicated that this option is also available to customers with load served by "behind the meter" generation [FN230] that seek to eliminate the load from their network load ratio calculation.

(1) Multiple Control Area Network Customers

Rehearing Requests

A number of entities argue that excluding load from the designation of Network Load does not solve the pancaking problem and results in the network customer paying even more transmission charges. They contend that a network customer must still pay two network charges and point-to-point charges to be able to operate its resources across two control areas. The Commission's approach, they argue, makes it impossible for a network customer with loads and resources in multiple control areas to integrate those loads and resources on an economic dispatch basis.[FN231] In essence, these entities state that a network customer must frequently dispatch resources in one transmission provider's control area (control area A) to serve that customer's load (in the case of a G&T cooperative, the load of a member system or third-party requirements customer) located in an adjacent control area of another transmission provider (control area B). As a result, they believe, the tariff essentially requires that network load in control area B, served by resources in control area A, must be counted as load in control area B. Alternatively, they believe that the tariff allows the transmission of resources in control area A to load in control area B as point-to-point transmission that requires an additional charge. These entities argue that either of these situations produces uneconomic results for multiple control-area network customers.

To avoid these problems, these entities propose that a network customer be allowed to use its network service to transmit power and energy from resources in control area A to serve load in control area B without designating the control area B load as network load for billing purposes. These entities suggest that no additional compensation should be required if such transfers to load in adjacent control areas plus other network transactions on behalf of the transmission customer in control area A do not exceed the customer's coincident demand in control area A. They also maintain that the ultimate solution is a regional system operated by an ISO. At the very least, TDU Systems contends, the Commission should require provision of service to network customers with loads and resources ***12321** located on multiple systems under a rate that recovers the customer's load ratio share—but no more—of the transmission owners' collective transmission investment in the control areas that the customer straddles.

AMP-Ohio maintains that rational economic transmission pricing policies demand elimination of the pancaking of rates caused by the arbitrary ownership boundaries of individual utilities.

TAPS asks that the Commission clarify that the Commission will look closely at how to create and promote region-wide rates when evaluating mergers and market-based rate proposals. It argues that the Commission should be receptive to section 211 filings seeking non-pancaked rates and should establish a Stage 3 for the purpose of addressing directly the need for transmission access on a non-pancaked, regional basis.

Commission Conclusion

In the Final Rule, the Commission addressed concerns regarding pancaked rates for network service for customers with load in multiple control areas.[FN232] Tariff section 31.3 allows a network customer the option to exclude all load from its designated network load that is outside the transmission provider's transmission system, and to serve such load using point-to-point transmission service.

NRECA and TDU Systems, however, argue that network customers located in multiple control areas should not have to pay for any additional point-to-point transmission service to make sales to non-designated load located in a separate control area. We disagree. Because the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service.

AMP-Ohio's concerns regarding "arbitrary ownership boundaries of individual utilities," and TAP's proposal to require regional rates are beyond the scope of Order No. 888.[FN233] However, as the Commission explained in the Final Rule, it encourages the voluntary formation of regional transmission groups, as well as the establishment of regional ISOs, and will address those matters on a case-by-case basis.

(2) Twelve Monthly Coincident Peak v. Annual System Peak

Rehearing Requests

Several utilities ask that the Commission eliminate the requirement that charges for network service be calculated using a 12-month rolling average load ratio share and allow utilities discretion to determine the way network customers pay.[FN234] They assert that the requirement makes it impossible to recover the full cost of service when customers begin or terminate service. They suggest a unit charge based on a formula rate that is trued up each year or a month-by-month load ratio share calculation.

NE Public Power District states that the definition of load ratio share in section 1.16 of the pro forma tariff, taken together with sections 34.2 and 34.3 of the pro forma tariff require the use of the 12-CP method and the inclusion of losses to the generator bus. This, it argues, is inconsistent with the Commission's statement that "[u]tilities that plan their systems to meet an annual system peak * * * are free to file another method if they demonstrate that it reflects their transmission system planning." (NE Public Power District at 22-23). NE Public Power District argues that utilities should be allowed to use CP demands measured at delivery points at some common specified voltage. It further asks the Commission to clarify whether the monthly peak includes or excludes transmission losses.

EEI and AEP argue that transmission reservations for services of less than one month's duration and any discounted firm transactions should not be counted in the load ratio calculation when determining the 12 CP on point-to-point rates, but that the revenues from these services should be credited to all firm transmission users.

Montana Power argues that the Commission's pricing approach discriminates against native load customers because all non-network uses of the system do not occur at full, non-discounted prices for the entire month and the effects of discounts will be shouldered by native load customers. According to Montana Power, this is a disincentive to utilities to offer discounts and creates a possibility of gaming by network customers buying one day firm point-to-point reservations to reduce their network load ratio shares.

Commission Conclusion

While the Commission reaffirmed the use of a twelve monthly coincident peak (12 CP) allocation method for pricing network service in the Final Rule, the Commission also stated:

[u]tilities that plan their systems to meet an annual system peak * * * are free to file another method if they demonstrate that it reflects their transmission system planning.[FN235]

Accordingly, utilities are free to propose in a section 205 filing an alternative to the use of the 12-month rolling average (e.g., annual system peak) in the load ratio share calculation, subject to demonstrating that such alternative is consistent with the utility's transmission system planning and would not result in overcollection of the utility's revenue requirement. Any proposed alternative would also be subject to any future filing conditions established by the Commission.[FN236]
We also are not convinced that we should require the calculation of load ratios using a particular method on a generic basis. Any such proposals, including those concerning the treatment of discounted firm transmission transactions in the load ratio calculation and revenue credits associated with such transactions, are best resolved on a fact-specific, case-by-case basis.

Finally, the Final Rule does not prohibit utilities from "us[ing] CP demands measured at delivery points at some common specified voltage" as claimed by NE Public Power District. Treatment of transmission losses can be accomplished in different ways by different transmission providers under the pro forma tariff, such as adjustment to a consistently applied voltage level.

Regarding NE Public Power District's allegation that certain sections of the pro forma tariff do not allow the use of the annual system peak method in the load ratio share calculation, the Commission recognizes that certain rate methodologies may require minor adjustments to the non-price terms and conditions to be consistent with the proposed rate methodology. However, any modifications to the non-price terms and conditions established in the pro forma tariff must be fully supported by the utility and the appropriateness of such proposed changes will be evaluated by the Commission for ***12322** consistency with the proposed rates or rate methodologies. The remainder of NE Public Power District's concerns are case-specific and should be raised by NE Public Power District at such time as a transmission provider makes a filing.

(3) Load and Generation "Behind the Meter"

Rehearing Requests

Several entities request clarification[FN237] concerning the definition of Network Load in pro forma tariff section 1.22, which provides, in pertinent part, that:

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.

These entities maintain that section 1.22 is too restrictive and is inconsistent with the Final Rule's treatment of load served from "behind the meter" generation.[FN238] Specifically, these entities request that the Commission clarify that a network customer can exclude from its designated network load a portion of load at a discrete point of delivery, which is served from generation behind the meter. In support of this position, a number of petitioners cite to FMPA v. FPL, 74 FERC 61,006 at 61,012-13, in which they claim the Commission allowed network customers to exclude load served by behind the meter generation.[FN239]

TAPS asserts that there is no operational or economic reason to require the designation of all load at a discrete point of delivery as network load.

FMPA argues that network customers should not be charged a network rate to use their own transmission (or distribution) system to serve loads that are located beyond the transmission owner's system. FMPA interprets the Final Rule on this issue as allowing a network customer that has behind-the-meter generation to serve part of its behind the meter load from such generation; thus, a customer can exclude that load, which is served without using the transmission provider's transmission system, from the load ratio share. FMPA's interpretation of section 1.22 is that "a network customer may not import power using both point-to-point and network transmission service at the same delivery point, but that this Section does not prevent a network customer from serving load from generation when both are behind the delivery point and when the transaction does not rely upon use of the transmission provider's transmission system." (FMPA at 5). FMPA requests that the Commission clarify the language in section 1.22 consistent with its interpretation above.

Michigan Systems asks the Commission to modify section 1.22 because the "clause may be interpreted to require network integration transmission service customers to pay a second time for the transmission of power that is already being transmitted under other arrangements, such as transmission ownership. The clause could also be interpreted to allow the transmission provider to charge customers for the transmission of power which does not use the transmitter's system, such as for transmission from 'behind the meter' generation to 'behind the meter' load." (Michigan Systems at 5-13).

Wisconsin Municipals ask the Commission to "clarify that a partial designation is appropriate if (1) only part of the load behind a particular delivery point relies upon the transmission provider's transmission system for service or (2) a network customer is responsible for serving only a portion of the load behind a discrete delivery point." (Wisconsin Municipals at 17-18).

Blue Ridge asks the Commission to clarify that it intended to allow for multiple ownership of resources by customers who are not network customers.

Utility Position

FPL and Carolina P&L ask the Commission to clarify that section 1.22 and the Rule (see also Original Sheet No. 94 and FMPA I, 67 FERC 61,167 at 61,481-82 (1994)) mean that regardless of whether or not a customer has behind the meter or local generation at a delivery point, if a customer wants to purchase network service to serve load at a delivery point, it must purchase network service for all such load—the customer cannot split the load into network and point-to-point components at a specific point of delivery.[FN240] Otherwise, FPL states, there would be a split system with the potential to game the system and problems with how it would work.

AEP argues that the option in section 1.22 of excluding load from network load should be deleted. AEP states that, as the Commission recognized in its original FMPA v. FPL order, the provision is contrary to the comparability standard. Specifically, AEP argues that transmission-owning utilities do not and cannot offer themselves partial integration service electing to pay only a portion of the network costs, but rather must pay for the entire network, which integrates all of the transmission-owning utility's resources and loads. According to AEP, the load served by behind-the-meter generation is not isolated from the system, which is there to serve that load when the behind-the-meter generation is unavailable. Allowing a network customer to use short-term non-firm point-to-point transmission, AEP asserts, allows customers to evade a large portion of the network's costs, which they will do on an unconstrained system such as AEP.

Commission Conclusion

We disagree that the prohibition in tariff section 1.22 against a network customer designating only part of a load at a discrete point of delivery as network load is either inconsistent with the Final Rule's treatment of generation "behind the meter" or is contrary to the Commission's decisions in FMPA I and FMPA II.

The Commission addressed "behind the meter" generation in the Final Rule as follows:

if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so. [citing Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC 61,006 (1996), reh'g pending.] Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by 'behind the meter' generation that seek to eliminate the load from their network load ratio calculation.[FN241]

Implicit in the Commission's discussion of this issue in the Final Rule and also in FMPA I and FMPA II, in permitting ***12323** the "exclusion of a particular load," is that the Commission will allow a network customer to exclude the entirety of a discrete load from network load, but not just a portion of the load served by generation behind the meter.

In its request for rehearing of FMPA I, FMPA requested that the Commission confirm its interpretation of the Commission's finding in FMPA I that:

[FMPA] can choose to serve an amount of load in a city from generation in the city, so long as FMPA does not sometimes serve that level of load from external generation or use that generation to serve member loads outside the city.[FN242]

On rehearing in FMPA II, the Commission did not grant FMPA's request to allow a partial designation of network load. Furthermore, the Commission provided an example of how FMPA could request that certain of its loads and resources be excluded from network integration transmission service. The Commission explained that FMPA could choose to exclude the loads of the cities of Ft. Pierce and Vero Beach from the request for network integrated transmission service and alternatively request point-to-point transmission service to transmit power from resources in those cities to other FMPA members or from FMPA member cities to Ft. Pierce and Vero Beach.[FN243] The Commission neither stated that it would allow a partial designation of a discrete load as network load nor provided any examples of such treatment.

Additionally, throughout the pro forma tariff, network customers are consistently prohibited from designating only a portion of a discrete network load. For example, tariff section 31.2 provides:

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. [Emphasis added]

Accordingly, we find that no inconsistency exists between the tariff language and either the language in the Final Rule or the Commission's findings in FMPA I or FMPA II.

In support of its position to allow a partial designation of network load at a point of delivery, TAPS claims that there are no operational reasons to require the designation of all load at a discrete point of delivery as network load. We disagree. Utilities, both commenting on the NOPR and on rehearing (e.g., AEP rehearing at 19-20 and Florida Power & Light at 14-18), express concern that customers allowed to divide a discrete load between point-to-point and network services would create a "split system." The concept of allowing a "split system" or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the integration of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated—it is either fully integrated or not integrated. Furthermore, such a split system creates the potential for a customer to "game the system" thereby evading some or all of its load-ratio cost responsibility for network services.[FN244]

For example, FMPA asserts that if a FMPA member city has a peak load of 100 MW and behind the meter generation of 75 MW, FMPA should be allowed to designate a portion of its load as network load (e.g., 60 MW), and to serve the remaining load (e.g., 40 MW) from its behind-the-meter generation.[FN245] However, as a number of utilities note, this would lead to the possibility of gaming the system. For example, if at the time of the monthly system peak the FMPA member city generates more than 40 MW (or takes short-term firm transmission service (or a combination of the two)), it may be able to lower its monthly coincident peak load for network billing purposes,[FN246] and thereby reducing if not eliminating its load-ratio cost responsibility for network service. Because network and native load customers bear any residual system costs on a load-ratio basis, any cost responsibility evaded by a network customer in this manner would be borne by the remaining network customers and native load.

FPL also raises several fundamental operational problems associated with allowing partial network service or creating a "split system:"

If all the loads are included in a single control area, how does the transmission provider know what portion of the power delivered is serving the point-to-point load (which presumably would not be counted toward the network's load ratio)?

Using the same 100 MW load example previously mentioned where there is a 40/60 network/point-to-point split, there would have to be a determination of how the split would be done in non-peak situations. Are the first 40 MW of load all network load, or all point-to-point load, or split on a 40/60 basis?

If the system purchases economy power from non-local resources, how is that delivery allocated between the network portion (for which there would be no point-to-point scheduling, curtailment, or transmission charges) and the point-to-point portion (which must be arranged and paid for separately under a point-to-point tariff)?

The bottom line is that all potential transmission customers, including those with generation behind the meter, must choose between network integration transmission service or point-to-point transmission service. Each of these services has its own advantages and risks.[FN247]

In choosing between network and point-to-point transmission services, the potential customer must assess the degree of risk that it is willing to accept associated with the availability of firm transmission capacity. Customers choosing point-to-point service, based solely on the amount of transmission capacity reserved (or contract demand), may face a relatively higher risk associated with the availability of firm transmission capacity. For example, if a customer with a peak load of 100 MW, and behind the meter generation of 75 MW, chooses to serve a portion of its load with point-to-point transmission service (e.g., 60 MW) and the remaining load (e.g., 40 MW) with its behind-the-meter generation, this customer faces the risk that, should its generation behind the meter become unavailable, the transmission provider may not have firm transmission capacity available to serve the remaining 40 MW of that ***12324** customer's load. One way to minimize this risk would be for the customer to reserve and pay for additional firm point-to-point transmission service to protect against the unavailability of its behind-the-meter generation. Alternatively, the customer could choose network service in which the transmission provider will plan and provide for firm transmission capacity sufficient to meet the customer's current and projected peak loads, including integration of the customer's behind-the-meter generation as a network resource.

For the reasons stated above, a network customer will not be permitted to take a combination of both network and point-to-point transmission services under the pro forma tariff to serve the same discrete load. Accordingly, the requests for rehearing to modify tariff section 1.22 are hereby rejected.

Moreover, the Commission will allow a network customer to either designate all of a discrete load[FN248] as network load under the network integration transmission service or to exclude the entirety of a discrete load from network service and serve such load with the customer's "behind-the-meter" generation and/or through any point-to-point transmission service.[FN249]

(4) Existing Transmission Arrangements associated with Generating Capacity Entitlements (e.g., "preference power" customers of PMAs)

Rehearing Requests

Several entities argue that section 1.22 of the pro forma tariff is arbitrary and cannot be reconciled with the Final Rule's determination not to abrogate existing agreements.[FN250]

Specifically, several transmission customers claim that the prohibition against designating only part of the load at a discrete point of delivery is problematic for customers with existing transmission arrangements for receiving preference power or capacity entitlements from power marketing agencies (PMAs). For example, Central Minnesota Municipal argues that the limiting language of section 1.22 should be eliminated as it would preclude Mountain Lake (a member of Central Minnesota Municipal) from using network transmission and, at the same time, point-to-point transmission for WAPA power under a separate arrangement. These transmission customers assert that if they designate all of the load at a discrete point of delivery as network load, and pay for such network load on a load-ratio basis, then the transmission provider is paid twice for the same transmission service—once through the existing transmission arrangement and a second time through the network service.

NRECA and TDU Systems argue that if a customer chooses to use network service under the pro forma tariff to supplement its existing arrangements to meet future full requirements, the Commission should amend section 1.22 so the transmission provider cannot overcharge the customer:

A Network Customer may elect to designate less than its total load as Network Load. Where a Network Customer has elected not to designate a particular load as a Network Load, the Network 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, unless such non-designated load is served pursuant to other arrangements. [FN[251]]

Alternatively, the transmission customer may choose not to designate any load at a discrete point of delivery as network load. However, these transmission customers note that the preference power allotments received from PMAs typically do not equal the total load of a customer at a discrete point of delivery. Therefore, the customer would need to acquire additional point-to-point transmission service for any remaining transmission needs. Accordingly, these transmission customers conclude that the existence of their current transmission arrangements precludes them from receiving network service which they claim does not allow the comparable use of the system that the transmission provider enjoys.

Commission Conclusion

The Commission recognizes that existing power and transmission arrangements represent a transitional problem as customers begin to take service under the pro forma tariff. Clearly, the Commission did not intend for a transmission provider to receive two payments for providing service to the same portion of a transmission customer's load. Any such double recovery is unacceptable and inconsistent with cost causation principles. Neither did the Commission intend to allow a transmission customer to designate less than its total load as network load at a discrete point of delivery even though a portion of that load is served under a pre-existing contract. We clarify that such a transmission customer has several alternatives it can pursue using either point-to-point or network transmission service.

Using network transmission service, the network customer would designate its existing generation supply contract(s) as a network resource(s) and the associated load served under such contract(s) designated as network load. The network customer then has two options: pursue negotiations with the transmission provider to obtain a credit on its network service bill for any separate transmission arrangements or for the unbundled transmission rate component of the existing generation supply contract or (2) seek to have any separate transmission or the unbundled transmission rate component of its generation supply contract eliminated in recognition of the network transmission service now being provided and paid for under the tariff.[FN252]

Using point-to-point transmission service, the transmission customer would identify the discrete points of delivery being served under existing generation supply and existing transmission contracts and acquire additional point-to-point transmission service under the tariff for any remaining load at those discrete points of delivery.

Any of these three alternatives should address concerns regarding the possibility of double recovery. Furthermore, a transmission customer may file a complaint under section 206 with the Commission to address any claims of double recovery that it is unable to resolve with the transmission provider.

d. Annual System Peak Pricing for Flexible Point-to-Point Service

In the Final Rule, the Commission indicated that it will allow a transmission provider to propose a formula rate that assigns costs ***12325** consistently to firm point-to-point and network services.[FN253] The Commission added that it will no longer summarily reject a firm point-to-point transmission rate developed by using the average of the 12 monthly system peaks.

The Commission explained that it still believed that it was appropriate for utilities to use a customer-specific allocated cost of service to account for diversity, but based on the changed circumstances since Southern Company Services, Inc., 61 FERC 61,339 (1992) (Southern), it indicated that it would now permit an alternative. Thus, the Commission indicated that it will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads.

In order to prevent over-recovery of costs for those who use this approach, the Commission explained that it will require transmission providers to include firm point-to-point capacity reservations in the derivation of their load ratio calculations for billings under network service. In addition, the Commission explained that revenue from non-firm transmission services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates. The Commission noted that the combination of allocating costs to firm point-to-point service and the use of a revenue credit for non-firm transmission service will satisfy the requirements of a conforming rate proposal enunciated in our Transmission Pricing Policy Statement.[FN254]

Rehearing Requests

Blue Ridge maintains:

The sea change in the Commission's approach to the pricing of transmission services is not warranted by any claimed change in circumstances and Blue Ridge accordingly requests rehearing and rejection of the new approach. At a minimum, the Commission should clarify that any deviation from use of an annual peak divisor (or other methodology based on system capability) for setting point-to-point transmission rates will be considered only on a case-by-case basis.

TAPS also argues that the use of the same denominator for two different services is inconsistent, unjust and discriminatory. It asserts that the Commission should use a system capability divisor for allocating fixed costs between reservation-based and load-based firm service.

TAPS also asserts that most utilities plan their transmission systems to cover the annual system peak estimated conservatively on the higher side in order to meet unusually high loads reliably, rather than planning on the basis of the twelve monthly peaks as stated in Order No. 888. Therefore, TAPS asks that the Commission maintain 1 CP pricing for point-to-point service. TAPS argues that the Commission should allow transmission providers and customers to demonstrate the appropriate measure for each transmission system's capability in utility-specific proceedings.

If the Commission uses a 12 CP denominator, TAPS requests that the Commission clarify that capacity reservations should be established consistently with that denominator and should recognize the inappropriateness of using such rates as a cap for non-firm rates. It asserts that non-firm rates should be limited to actual variable costs of transmission, plus losses, plus a modest adder as a contribution toward fixed costs. At the very least, TAPS argues that the cap should be developed using a more appropriate denominator, e.g., system capability.

TAPS further argues that if the rate divisor is based on experienced 12 CP, the capacity reservations and the divisor should be measured at the delivery points (as it is for native load customers), not the higher of the receipt or delivery points, to avoid a mismatch between the rate divisor and billing determinants.[FN255]

Wisconsin Municipals and TAPS argue that if a 12 CP divisor is used, customers must have the flexibility to vary their monthly nomination under the point-to-point tariff.

Commission Conclusion

With respect to TAPS argument that the annual system peak method would be appropriate for most systems, the Commission has determined in Order No. 888 that this issue is best resolved on a case-by-case basis and specifically provided utilities the opportunity to propose to use other allocation methods, including the annual system peak method sought by TAPS.[FN256]

The Commission already recognized the potential for a mismatch between the rate divisor and billing determinants that TAPS now raises on rehearing. We explicitly stated in the Final Rule that [t]he adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with all firm point-to-point service customers plus the monthly contract demand reservations for all firm point-to-point service.[FN[257]]

Use of the adjusted system monthly peak loads in the rate divisor for flexible point-to-point transmission service eliminates the mismatch concern raised by TAPS.

We have also fully addressed in the Final Rule those arguments objecting to the use of the average of the 12 monthly peaks in determining a firm point-to-point transmission rate and no further discussion is required. The other arguments raised with respect to this section are fact specific and best addressed in individual rate proceedings where the use of an annual system peak versus an average of the 12 monthly peaks in determining a firm point-to-point transmission rate is more appropriately evaluated.

e. Opportunity Cost Pricing

(1) Recovery of Opportunity Costs

The Commission emphasized in the Final Rule that it had fully explained its rationale for allowing utilities to charge opportunity costs in Northeast Utilities and Penelec.[FN258] The Commission also explained that transmission providers proposing to recover opportunity costs must adhere to the following requirements:

(1) A fully developed formula describing the derivation of opportunity costs must be attached as an appendix to their proposed tariff;

(2) Proposals must address how they will be consistent with comparability; and

(3) All information necessary to calculate and verify opportunity costs must be made available to the transmission customer.

Rehearing Requests

VT DPS disputes the Commission's holding with respect to opportunity costs and argues that rate filings seeking recovery of opportunity costs should be summarily rejected. It asserts that, contrary to statements by the Commission, courts have not endorsed opportunity cost pricing for transmission customers and maintains that the Commission's failure to consider objections to opportunity cost ***12326** pricing on the merits "directly flouts the court's ruling" in Northeast Utilities. According to VT DPS, opportunity costs are inherently unverifiable: "there are insuperable difficulties in proving the existence of lost opportunity costs in any fashion which can readily and objectively be applied." At a minimum, VT DPS asserts, opportunity costs arising more than five years out are unverifiable and should not be permitted. Moreover, VT DPS argues that the right to challenge the verifiability of opportunity costs is not adequate protection because it is wasteful and burdensome (citing Cajun Electric Power Cooperative v. FERC, 28 F.3d 173 at 179 (D.C. Cir. 1994) (Cajun)).

VT DPS also asserts that the Commission's treatment is inconsistent with its treatment of gas pipeline pricing policies, which do not permit the assessment of opportunity costs in gas pipeline transportation rates. In addition, VT DPS asserts that opportunity cost pricing for firm transportation service would allow the transmitting utility to charge more for firm transmission of a third party's power supplies than it charges its own native load for the transmission component of native load service. Finally, VT DPS claims that opportunity cost pricing contravenes Cajun because opportunity cost pricing has a chilling effect on competition in New England and nationally. VT DPS challenges whether a tariff provision that permits the imposition of opportunity costs "precludes the mitigation of [a utility's] market power."

CCEM asserts that there is no justification for allowing opportunity cost charges when such charges can be eliminated in the secondary or released capacity market, without the discriminatory charge. It notes that opportunity costs are not allowed in any other industry and the Commission should not allow recovery of lost profits.

American Forest & Paper argues that the only way to ensure comparability is to require that transmission services are priced for all customers based upon embedded cost principles (including pricing for expansions). It opposes opportunity cost pricing as being discriminatory because wheeling customers are required to compensate the transmitting utility for its lost opportunities to make economy purchases or sales to benefit native load. It further argues that transmission capacity was not designed to facilitate non-firm, unplanned economy purchases or sales on behalf of native load. American Forest & Paper also asserts that allowing redispatch costs incorrectly presupposes that native load has a superior right to the transmission system. According to American Forest & Paper, neither of these costs (opportunity/redispatch) should be imposed on the former sales, now transmission-only, customers—the transmission customer is no more responsible for the alleged transmission constraint than the existing native load customer who adds to its requirements or the new customer locating in the service territory. It maintains that firm transmission contracts cannot by definition displace opportunity sales because there is no "opportunity" until there is capacity in excess of the firm transmission contractual commitments. In addition, American Forest & Paper asserts that opportunity cost pricing may create difficulties for IPPs, i.e., a lender may not finance projects because of cost uncertainty related to varying revenue flows caused by opportunity cost pricing. It believes that utilities should be required to establish a separate subsidiary to make opportunity purchases or sales on its behalf, which may minimize self dealing.[FN259] It further asserts that expansions should be subject to embedded cost pricing—unlike in gas pipeline expansions, electric transmission expansions invariably affect an integrated network.

CCEM asserts that, if opportunity cost pricing is maintained, transmission customers should be given the information they need to avert or mitigate opportunity-cost exposure. In particular, it argues that customers need information on the run status and cost of generating units that the transmission provider controls in advance of any proposed redispatch. In addition, CCEM argues that transmission providers should be required to inform customers of a redispatch in advance.

Commission Conclusion

As an initial matter, many of the arguments raised are collateral attacks on Penelec, Northeast Utilities, and the Commission's Transmission Pricing Policy Statement. These matters are not the subject of this proceeding, but rather Order No. 888 simply applies the policy already in place. Therefore, these arguments are not properly raised in this proceeding.[FN260]

The Commission does not believe that any changes are necessary to its policy on opportunity cost recovery.[FN261] In the Final Rule, we fully explained our rationale for allowing utilities to charge opportunity costs and no arguments have been presented on rehearing that would persuade us otherwise.

As has been our policy, we will continue to determine the appropriateness of opportunity cost pricing proposals on a case-by-case basis. We continue to believe that opportunity cost pricing will promote efficient decision-making by both transmission owners and users and will not result in unduly discriminatory or anticompetitive pricing. We have stated that because any transmission pricing proposal must meet the comparability standard, we will have ample opportunity to address any concerns that opportunity cost pricing may be unfair and anticompetitive or otherwise inconsistent with the comparability standard, including those concerns raised by CCEM with respect to the need for advance information as to any proposed redispatch.

We note that in compliance filings made pursuant to Order No. 888, most utilities did not make the tariff changes necessary to charge opportunity costs to customers under the pro forma tariff. Absent a subsequent section 205 filing, these transmission providers will not be able to charge opportunity costs under their compliance tariffs. Where transmission providers did modify their tariff to allow for opportunity costs, the Commission is reviewing the proposed charges on a case-by-case basis.

(2) Redispatch Costs

In the Final Rule, the Commission clarified that redispatch is required only if it can be achieved while maintaining ***12327** reliable operation of the transmission system in accordance with prudent utility practice.[FN262]

The Commission further explained that the recovery of redispatch costs requires that: (1) a formal redispatch protocol be developed and made available to all customers; and (2) all information necessary to calculate redispatch costs be made available to the customer for audit. The Commission also noted that the rates proposed must meet the standards for conforming proposals in the Transmission Pricing Policy Statement.

The Commission also explained in the Final Rule that if the transmission provider proposes to separately collect redispatch costs on a direct assignment basis from a specific transmission customer, the transmission provider must credit these revenues to the cost of fuel and purchased power expense included in its wholesale fuel adjustment clause.[FN263]

Rehearing Requests

TAPS asserts that there is too much uncertainty with respect to the treatment of redispatch costs. It asserts that the Commission should require a section 205 filing for each corridor/constraint for which redispatch costs are intended to be shared among the transmission provider and network customers. Once there has been a determination regarding a particular corridor/constraint, TAPS argues that "it would be appropriate to charge network customers for redispatch costs through a mechanism with no fewer protections than a fuel clause." It further argues that redispatch costs, like opportunity costs, should be capped at the cost of the upgrade and, at the least, the Commission should clarify that application of the redispatch sharing provision should be adjudicated in particular cases.

TDU Systems states that it does not object to a redispatch obligation that is necessary to ensure transmission system reliability, but they object to the fact that a transmission provider can determine that a transmission constraint will arise as a result of the sale of additional firm transmission service by the transmission provider. It asks the Commission to clarify that the transmission constraint that would trigger a redispatch obligation cannot be caused by a transmission provider's sale of additional firm transmission capability.

Wisconsin Municipals asks the Commission to clarify that recovery of redispatch costs on a load ratio basis, without a section 205 filing, is limited to when such action is necessary for reliability reasons alone (not for economic reasons), and that in all other circumstances a section 205 filing must be made and costs directly assigned to the customer receiving the economic benefit of the redispatch. It further asserts that if redispatch is allowed for economic reasons, it must be offered on a comparable, non-discriminatory basis to all customers and the transmission provider, provided the beneficiary agrees to accept a direct assignment.

Several utilities argue that redispatch costs are a subset of opportunity costs and that the Commission should not use both terms in the tariff because it implies different standards apply to transmission providers and their customers (e.g., sections 23.1 and 27).[FN264] They request that the Commission only use the term "redispatch costs" in the pro forma tariff and impose the same redispatch obligations on network customers as are imposed on transmission providers.

No rehearing requests addressed the subject of fuel adjustment clause treatment for redispatch costs.

Commission Conclusion

The Commission believes that the obligation to create additional transmission capacity to accommodate a request for firm transmission service should properly lie with the transmission provider, not a network customer.

The Commission clearly established in the Final Rule that utilities are to be given "substantial flexibility * * * to propose appropriate pricing terms, including opportunity cost pricing [of which redispatch costs are a subset], in their compliance tariff."[FN265] The Commission further required that any such rate proposals must meet the standards for conforming proposals in the Transmission Pricing Policy Statement. Accordingly, TAPS is free to pursue its concerns in any relevant compliance filings.

Tariff sections 33.2 and 33.3 clearly establish that redispatch of all Network Resources and the transmission provider's own resources are only to be performed to maintain the reliability of the transmission system, not for economic reasons. Such costs are to be shared between network customers and the transmission provider on a load ratio basis. Similarly, the Commission clarified in Order No. 888, in modifying the transmission customer's redispatch obligation, that such change was "to limit the redispatch obligation to reliability reasons."[FN266] Therefore, no further clarification is necessary.

Other redispatching provisions under the tariff (e.g., sections 13.5 and 27) refer to situations where the transmission provider can relieve a system constraint more economically by redispatching the transmission provider's resources than through constructing Network Upgrades in order to provide the requested transmission service. However, in this circumstance, redispatch is conditioned upon the eligible customer agreeing to compensate the transmission provider for such redispatch costs. Section 13.5 of the pro forma tariff further requires that any such redispatch costs to be charged to the transmission customer on an incremental basis must be specified in the customer's service agreement prior to initiating service. These tariff requirements would appear to satisfy Wisconsin Municipals concerns because a section 205 filing must be made to directly assign costs to the customer receiving the economic benefit of the redispatch.

Regarding the argument that only the term "redispatch costs" should be used in the pro forma tariff, we note that the Commission followed this suggestion in drafting the pro forma tariff. The only exception is the use of opportunity costs in section 23.1 of the tariff, which caps the compensation for resellers at the higher of: (1) the original rate, (2) the transmission provider's maximum rate on file at the time of the assignment or (3) the reseller's opportunity cost. We further note that their concerns that different standards may be applied to transmission providers than to their customers are addressed in section IV.C.6 (Capacity Reassignment).

f. Expansion Costs

In the Final Rule, the Commission allowed transmission providers to propose any method of collecting expansion costs that is consistent with the Commission's transmission pricing policy.[FN267] The Commission explained that "or" pricing sends the proper price signal to customers and promotes efficiency and further indicated that "and" pricing will not be allowed.

The Commission also indicated that any request to recover future expansion *12328 costs will require a separate section 205 filing.

Rehearing Requests

Several entities argue that requiring section 205 filings for all transmission expansion costs would impose difficult burdens on transmission providers that use formula rates because they would have to try to distinguish between replacement costs, which are included in formula rates, and expansion costs, which are not.[FN268] They assert that section 205 filings should be required only for system expansion costs that the transmission provider proposes to recover on a direct assignment or incremental cost basis, but not for costs to be recovered on an embedded cost basis.

TDU Systems maintain that to the extent Order No. 888's provisions concerning direct assignment of transmission facilities indicate a change in the historic policy of rolling transmission investments into rate base, there is a risk TDUs will bear a disproportionate share of the transmission burden relative to transmission owners under the Commission's "or" pricing policy. According to TDU Systems, transmission owners should be required to permit customers to substitute their own lower cost capital for that of the owner's.

SoCal Edison and Carolina P&L ask the Commission to clarify that a transmission provider has no obligation to build or upgrade its facilities for short-term firm point-to-point transmission customers (§§13.5, 15.4 and 1.13). SoCal Edison states that if a transmission provider is required to build, the Commission should clarify that any costs must be directly assigned to the requesting customer.

Commission Conclusion

The Final Rule does not change the Commission's filing requirements for recovery of transmission expansion costs or other transmission-related expenses. The Rule does not impose a section 205 filing requirement to the extent that existing formula rates do not require that such a filing be made to add transmission investment. However, consistent with the Commission's transmission pricing principles in effect prior to Order No. 888, a decision to price transmission on an incremental cost basis, or to directly assign facilities, are cost assignments that require a section 205 filing.

The Final Rule also does not change the Commission's transmission pricing policies. Under our transmission pricing policy, a utility is still permitted to charge the higher of incremental expansion costs "or" a rolled-in embedded cost rate. There is no bias in the Final Rule that should cause TDU customers or any other customer to pay a disproportionate share of transmission costs. Moreover, we note that we also encourage joint planning/building options and regional solutions such as RTGs and ISOs.

We do not believe that any change is necessary with regard to the obligation to build or expand. While both sections 13.5 and 15.4 obligate the transmission provider to expand or upgrade its transmission system to accommodate an application for firm point-to-point transmission service, these sections are conditioned upon the transmission customer agreeing to compensate the transmission provider for such upgrade. In light of this compensation requirement, we do not anticipate that transmission providers will be requested to upgrade facilities in order to accommodate requests for short-term point-to-point transmission service. However, in the unlikely event that a short-term firm point-to-point transmission customer agrees to pay the costs of such upgrades, we believe that it is appropriate to require a transmission provider to expand its system to accommodate the request.

g. Credit for Customers' Transmission Facilities

In the Final Rule, the Commission concluded that credits related to customer-owned facilities are more appropriately addressed on a case-by-case basis, where individual claims for credits may be evaluated against a specific set of facts.[FN269] The Commission stressed that while certain facilities may warrant some form of cost credit, the mere fact that transmission customers may own transmission facilities is not a guaranteed entitlement to such a credit. The Commission further explained that it must be demonstrated that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider in order to establish a right to credits. The Commission also noted that consistent with its ruling in FMPA II,[FN270] if a customer wishes not to integrate certain loads and resources, and thereby exclude them from its load ratio share of the allocated cost of the integrated system, it may do so by separately contracting for point-to-point transmission service.

Rehearing Requests

APPA asserts that several differences between the treatment of transmission customers' and transmission providers' facilities are not comparable and must be corrected: (1) transmission providers' facilities include those owned, controlled or operated by the transmission provider, but to obtain credit, transmission customers must own the facilities; (2) transmission providers are under no obligation to engage in joint planning and historically have refused, thus putting the matter beyond the control of the customer; and (3) facilities of the customer must serve all of the transmission provider's power and transmission customers, but a transmission provider can include facilities in rates that serve only certain customers. APPA also maintains that the Commission failed to provide sufficient guidance to allow customers to ascertain the type of transmission facilities for which they can expect to receive credit.

Several entities assert that the standard as to existing customer-owned facilities is inherently ambiguous—the Final Rule preamble says integrated into the "plans or operations" of the transmitting utility, but section 30.9 of the tariff says the "planning and operations" of the transmission provider (emphasis added).[FN271] Further, they assert, it is unreasonable to require, as a key to integration, that "the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities" because it may be that the facilities are necessary to provide network service to the customer that owns the facilities and a credit would be appropriate. They argue that if transmission facilities serve load included in the network customer's network load, the transmission customer should get a credit.

Blue Ridge states that "[i]f the Commission does intend to change its standard or otherwise codify the result of FMPA II, then Blue Ridge urges rehearing and suggests a more analytical, policy oriented approach to the issue." (Blue Ridge at 31). It recommends adding the following language to the end of section 30.9 of the tariff concerning credit for new facilities: "or if such facilities are integrated with, and support the ***12329** Transmission Provider's Transmission system." (Blue Ridge at Attachment 1).

FMPA argues that a transmission provider can avoid paying credits for transmission that is functionally the same as that of the transmission provider simply by refusing to jointly plan. It asserts that the Commission should adopt either the Commission's integration test, without requiring joint planning, or a functionality test that considers whether the facilities of the customer and transmission provider are similar. Moreover, it argues that a more inclusive definition of the grid would better achieve comparability and competitive generation markets and would remove incentives to avoid joint planning. It argues that crediting customer-owned transmission also promotes the establishment of regional grids.

Several entities state that the standard as to future network customer-owned facilities should be modified to make joint planning mandatory on the part of the transmission provider, who otherwise has little incentive to cooperate and coordinate.[FN272] They claim that in joint planning, plans cannot be developed by the transmission provider alone. They further argue that the Commission should not deem the lack of joint planning dispositive of the operation and planning issue.

TAPS asks the Commission to clarify that credits will be provided for existing, as well as future, facilities if the integration requirement is met.

Wisconsin Municipals asks the Commission to clarify that the level of customer-owned credits is a rate issue and that if parties have negotiated provisions for credits, the Final Rule cannot be used by transmission providers to avoid the obligations undertaken in a settlement.

NRECA and TDU Systems assert that the Commission should not abandon its historical practice of rolling in transmission facilities for purposes of transmission pricing; otherwise, the Commission must examine the function of all transmission facilities in a transmission provider's rate base and exclude them if they are not "integrated" (referencing Order No. 888 at 317 n.452). They argue that because customers would have to file section 206 filings to enforce this, the Commission should require transmission providers to file under section 205 the identity of those facilities that will be included in the transmission rate base, those that will be excluded, and the supporting data.

Turlock wants the Commission to provide concrete guidelines as to the eligibility of facilities for customer credits. Moreover, Turlock asserts that credits may be appropriate for point-to-point customers as well—especially in Northern California where PG&E, according to Turlock, encouraged customers to build facilities. Turlock finds this particularly important where PG&E has proposed to switch from subfunctionalized ratemaking to system-wide rolled-in ratemaking. It asserts that, if there are system-wide rolled in rates without a credit provision, there may be a violation of the "or" pricing policy.

Several entities ask the Commission to clarify that the crediting provision works on a comparable basis for transmission customers and providers.[FN273] They ask the Commission to clarify that the phrase "serve all of its power and transmission customers" in section 30.9 is to be measured by the facilities that the transmission provider rolls into rate base to determine transmission rates and the transmission component of requirements rates. For example, they argue that because AEP rolls radial lines into rate base, comparable customer-owned lines should receive a credit. They also ask the Commission to clarify that the test that facilities are integrated into the planning and operations of the transmission provider is an objective standard that is satisfied by evidence that the transmission provider's load flow studies take into account the transmission customer's facilities. They assert that the standard should not be a subjective one that depends on whether the transmission provider says that it includes customer facilities in its planning and operations.

AMP-Ohio adds that the integration requirement should also be satisfied by evidence that the transmission provider includes costs in its rate base or transmission expenses that are associated with transmission facilities of utilities that it acquires. Michigan Systems also asks that the Commission clarify that the test in section 30.9 is a functional test and not whether the transmission owner says it is integrating its operations.

Michigan Systems states that it has no objection to leaving determinations of credits to rate cases, as an abstract matter, but asserts that the Commission should make clear that it will not implement newly-filed tariffs in a way that imposes multiple or inconsistent charges for transmission in the interim. Otherwise, it asserts, transmission dependent utilities may be out of business if they must wait years to get credit for grid transmission they already own and that they must pay to finance. Michigan Systems also states that it would be illegal to require systems to pay for transmission by applying a load ratio share based on total loads when they have made investments under contracts for transmission to serve a portion of those loads.

TAPS states that the Commission must define what it means by "integrated." TAPS asserts that the term should mean grid facilities used to integrate the network customer's resources and loads. It further asserts that the Commission should continue to use the test whether the facilities serve a comparable function. Unless a proper credit is provided, TAPS maintains, network customers could pay twice for transmission. TAPS adds that without proper crediting, the Commission cannot require load ratio pricing of network service.

TAPS asks the Commission to clarify the method it will use to calculate the credit in individual cases and suggests that the Commission adopt the method TAPS proposed in its initial comments in this proceeding.

With respect to joint ownership of transmission facilities or ownership of transmission facilities through a joint exercise of powers agency (JPA) or a Generation and Transmission Cooperative, TANC asks that the Commission provide for proportionate entitlement to a credit among those who have invested in, and are entitled to the use of, such facilities. TANC also argues that the credit should apply to facilities used to complete a transaction under the transmission provider's point-to-point tariff.

Further, TANC asserts that upon a showing that the facilities are integrated, the credit in section 30.9 should be mandatory and asks that the Commission provide guidance as to the method of either calculating or applying the credit.

Commission Conclusion

The Commission reaffirms its finding in Order No. 888 that the question of credits for customer-owned facilities is best resolved on a fact-specific, case-by-case basis.[FN274] Accordingly, the Commission does not believe that the rehearing requests seeking specific guidance regarding various aspects of ***12330** customer credits are appropriate for resolution at this time.[FN275]

In order to conform the Final Rule preamble language with the tariff provisions of Order No. 888,[FN276] we will modify section 30.9 of the pro forma tariff to provide that a customer may receive a credit for its own facilities if it demonstrates that "its transmission facilities are integrated into the plans or operations (instead of "planning and operations") of the transmission provider to serve its power and transmission customers."[FN277] The intent of section 30.9 of the pro forma tariff is that, for a customer to be eligible for a credit, its facilities must not only be integrated with the transmission provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid. Indeed, in the Final Rule we explicitly stated that the fact that a transmission customer's facilities may be interconnected with a transmission provider's system does not prove that the two systems comprise an integrated whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over these facilities.[FN278]

The Commission further stated in the Final Rule that where disputes over credits for customer-owned facilities arise, it encourages all parties not to seek formal resolution at the Commission, but to first pursue alternative dispute resolution. In this regard, the customer at the time it is requesting network service could also request that a study be undertaken by the company to analyze the impact and benefit of the customer's facilities provided to the integrated transmission network.

We share the concern of APPA and others that transmission providers have not allowed transmission customers to participate in the planning process for new transmission projects. Allowing potential transmission customers the opportunity to participate in transmission projects is important in ensuring that regional transmission needs are met efficiently. One way of accomplishing this goal is through an RTG, ISO, or other regional entity that has an open planning process. Where such entities do not exist, we strongly encourage public utilities to hold an open season for all transmission expansion projects, including those in response to a service request, so that all entities in the region have an opportunity to identify their future needs and participate in the project.

Finally, requests for the Commission to mandate joint-planning are addressed below in the discussion of section 1.12 of the pro forma tariff.

h. Ceiling Rate for Non-firm Point-to-Point Service

In the Final Rule, the Commission stated that it is important to continue to allow pricing flexibility.[FN279] The Commission explained that, in accordance with its current policies, the rate for non-firm point-to-point transmission service may reflect opportunity costs. The Commission further explained that, if a utility chooses to adopt opportunity cost pricing, the non-firm rate is effectively capped by the availability of firm service and is not subject to a separately-stated price cap. On the other hand, the Commission explained that, if a utility chooses not to adopt opportunity cost pricing, the non-firm rate is capped at the firm rate.

Rehearing Requests

Duquesne asks the Commission to clarify that the phrase "the non-firm rate is capped at the firm rate" does not mean that the Commission is deviating from its principles that non-firm transmission service must be priced in a manner that (i) reflects the interruptibility of the service, and (ii) is economically efficient.

Commission Conclusion
With regard to Duquesne's request, we clarify that the firm transmission rate simply represents a maximum rate or price cap for non-firm transmission prices. We emphasize that non-firm transmission prices should reflect the interruptibility of the service and should promote efficient use of the transmission system, subject to this price cap. Accordingly, while in some circumstances non-firm transmission rates may be set at the firm transmission rate level, the Commission expects that non-firm transmission rates would, in most instances, be priced below the price cap.

i. Discounts
In the Final Rule, the Commission stated that if a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own wholesale transactions, the same discounted rate must also be offered at the same time to non-affiliates on the same transmission path and on all unconstrained transmission paths.[FN280] In addition, the Commission required that discounts from the maximum firm rate for the provider's own wholesale use or its affiliate's wholesale use must be transparent, readily understandable, and posted on the transmission provider's OASIS in advance so that all eligible customers have an equal opportunity to purchase non-firm transmission at the discounted rate.[FN281] Finally, the Commission explained that discounts offered to non-affiliates must be on a basis that is not unduly discriminatory and must be reported on the OASIS within 24 hours of when available transmission capability (ATC) is adjusted in response to the transaction.

Rehearing Requests

Utility Position
A number of utilities assert that the affiliate discounting provision is too broad.[FN282] SoCal Edison asserts that if the affiliate discounting provision is kept, the requirement to discount similarly for non-affiliates on unconstrained paths should be limited to offers on the same day only for new transmission services and only for the duration of the service offered to the affiliate.

Entergy and Southwestern assert that the Commission should change the discount language, which provides that ***12331** whenever the transmission provider offers a discount to an affiliate, or attributes a discount to its own transaction, it must offer a comparable discount to all similarly situated transmission customers. Southwestern believes that the Commission does not justify its different treatment of discounts to affiliates and discounts to non-affiliates—section 205(b) of the FPA states that a public utility may not give any undue preference or advantage to any person. Southwestern also notes that for gas pipelines, the Commission required that affiliate discounts be available to similarly situated shippers (citing 18 CFR 161.3(h)(1)).

PacifiCorp suggests replacing the last sentence of section 37.6(c)(3) of the OASIS regulations with the following sentence: "With respect to any discount offered to its own power customers or its affiliates, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all Transmission Customers on the same transmission path and on all other unconstrained transmission paths parallel thereto for deliveries to the same Point of Delivery." It argues that the Commission's approach of requiring the same discount to all transmission customers on the same path and on all unconstrained transmission paths would discourage discounting, even when done to attract counter-wheeling to relieve constraints.[FN283]

Several utilities argue that the discount language should be changed to require only that the same discount be offered to all customers on the same path.[FN284] Otherwise, Montana Power asserts, transmission providers will be reluctant to offer discounts to its own marketers so as to protect revenues on other paths.

AEP suggests that the discount language be changed to require that the discount be made available for all unconstrained paths terminating at the same interface.

Illinois Power argues that the Commission should require discounts for equivalent (i.e., similarly situated) service requests, on the basis of location, term and time of service, which it asserts conforms to the Commission's standards for natural gas pipelines (citing 18 CFR 161.3(h)). Otherwise, it asserts, the Commission's approach will result in inefficient use of scarce transmission capacity and thereby discourage efficient bulk power trading.

VEPCO asserts that transmission providers must be given more flexibility to accommodate differences in regional wholesale markets and to maximize the movement of economical capacity and energy. It states that a transmission provider will provide discounts only if they are not detrimental to existing committed agreements or potential future revenue—revenue from additional sales must offset the decrease in revenues from making discounts. It suggests that preferential treatment can be reduced by the following constraints: (1) offer the same discount to all transmission requests to the same points of delivery for the same time, and (2) a discount should not apply to service already agreed to but not yet provided at that point. Utilities For Improved Transition adds the following constraint: evaluate request for discount on whether it would increase volume without reducing total revenues.[FN285] Florida Power Corp asserts that because communications regarding discounts must be posted on OASIS, preferential treatment would be readily apparent.

EEI states that the discount requirement has the potential to arbitrarily reduce the revenue that the transmission provider may be able to obtain over alternative paths that may be unconstrained, but of greater potential value than the path(s) identified as appropriate for discounting. It adds that the requirements for posting discounts should be the same regardless of affiliation and should be limited to the specific transmission path(s) discounted by the transmission provider.

Carolina P&L argues that the Commission should permit selective discounting of non-firm transmission service on a posted-in-advance (on OASIS) basis that will not create a most favored nations situation merely because the transmission provider or an affiliate availed itself of the posted discount.

Customer Position

Tallahassee asks the Commission to clarify that the transmission provider must automatically apply the discount to any eligible customer or, at the minimum, provide actual and timely notice of the discount's availability.

Similarly, PA Coops asserts that "[i]f transmission service is being discounted to any customer, affiliated or not, for a specific level of service at a specific point in time, it should be equally discounted to all customers receiving the same transmission service. To do otherwise is unduly discriminatory." (PA Coops at 11).

TAPS asserts that all discounts must be posted in advance, the reasons for the discounts should be transparent, the transmission provider should keep all requests for discounts in a log, and short-lived discounts should not be permitted.

Commission Conclusion

In response to the arguments raised with respect to discounting, we will revise our policy on discounting transmission service. This revised policy will assure consistency with our standards of conduct requirements, which preclude a utility's wholesale merchant function from having access to its transmission system information (including price) not posted on the OASIS that is not otherwise also available to the general public or that is not also publicly available to all transmission users. The revised policy also should result in less opportunity for affiliate abuse and enable better monitoring of potential abuse. Additionally, we have concluded that the same policy should apply regardless of whether the discount is for the transmission provider's own wholesale use (i.e., wholesale merchant function), for the transmission provider's affiliate, or for a non-affiliate.

A transmission provider should discount only if necessary to increase throughput on its system. While the potential for abuse is most obvious in situations involving the transmission provider's own wholesale use or use by an affiliate (own use/affiliate),[FN286] we must also be concerned with a transmission provider agreeing to discount to non-affiliates in any unduly discriminatory manner. To satisfy these dual concerns, we believe that any "negotiation"[FN287] between a transmission provider and potential transmission customers should take place on the OASIS. Toward this end, we believe three principal requirements are appropriate. (These requirements would remain even after negotiation takes place on the OASIS.)

First, any offer of a discount for transmission services made by the transmission provider must be announced to all potential customers solely by posting on the OASIS. This requirement, which will ensure that all potential transmission customers under ***12332** the pro forma tariff will have equal access to discount information, will guard against own use/affiliate customers gaining an unfair timing advantage concerning the availability of discounts.

Second, we will require that any customer-initiated requests for discounts occur solely by posting on the OASIS, regardless of whether the customer is an own use/affiliate or a non-affiliate. We have considered, and rejected at least for now, a more restrictive approach which would require that all discounts be initiated solely through offers by the transmission provider. Under such an arrangement, negotiations for discounts would effectively take place by customers accepting or not accepting the offered discount. While such an arrangement could better protect against affiliate abuse, it might be less efficient.[FN288] Accordingly, we will permit customer-initiated requests for discounts but will require that such requests be visible (via posting on the OASIS) to all market participants.

Finally, we will require that, once the transmission provider and customer agree to a discounted transaction, the details (e.g., price, points of receipt and delivery, and length of service) be immediately posted on the OASIS. This requirement will be equally applicable regardless of whether the customer is an own use/affiliate or non-affiliate.

We will also revise our policy with respect to the transmission paths on which a discount must be offered. Many petitioners argue that the policy in Order No. 888, particularly that the discount rate must be offered over all unconstrained paths, is too broad, and may provide disincentives for the efficient operation of the transmission grid. Their concerns include, for example, the possibility that the policy would inhibit the transmission provider from offering discounts that would relieve line constraints. For example, PacifiCorp argues that it would be reluctant to offer a discount on northbound power flows that would relieve transmission constraints on transmission paths that are normally used for southbound flows, if by virtue of discounting northbound flows, it would also be required to discount all unconstrained southbound flows. Another concern is that while requiring discounts on all unconstrained paths could conceivably result in more service being provided, it may not have that effect. Since the level of transmission revenues will decline if the discount applies to all unconstrained paths and this, in turn, could reduce the credit to firm transmission users for non-firm service revenues, transmission providers may simply decide not to discount a particular unconstrained path. In light of these persuasive arguments, we will no longer require the transmission provider to provide the same discount over all unconstrained paths.

Under our revised policy, if the transmission provider offers a discount on a particular path, i.e., from a point of receipt to a point of delivery, the transmission provider must offer the same discount for the same time period on all unconstrained paths that go to the same point(s) of delivery on the transmission provider's system. In this regard, a point of delivery includes an interconnection with another control area. Also, if a power purchaser can take delivery at more than one point of delivery (such as two substations serving a municipality), we would consider these to be the same point of delivery for discounting purposes.

This change provides some flexibility to transmission providers to set prices for transmission service efficiently and at the same time maintains the requirement that public utilities provide comparable service at rates that are not unduly discriminatory or preferential. The change is designed to ensure that the transmission owner will provide the same discounted service to its competitors that it provides to itself or its affiliates for their wholesale sales.

The Commission considered requiring the transmission provider offering a discount on a particular path to offer discounts on all unconstrained paths that go from the same points of receipt on the transmission provider's system and decided that such a requirement was not necessary to ensure comparability.

We further clarify that a transmission provider may limit its offers of discounts over the OASIS to particular time periods. There is nothing per se unduly discriminatory in offering a discount in one period and not in another.[FN289]

Finally, we recognize that even with this revised policy utilities may engage in affiliate abuse by offering discounts only at times or along paths that are of advantage to it or its affiliates. While requiring the posting of discount information on the OASIS does not completely eliminate the possibility of affiliate abuse, these procedures will allow ready identification of unduly discriminatory or preferential transactions, and thus make easier the preparation of complaints that the transmission provider is engaging in a pattern of discounting that indicates affiliate abuse, such as offering discounts preferentially at times or on paths that only the transmission provider or its affiliate can take advantage of, without offering discounts at times or on paths that its competitors can take advantage of.

We will require that all "negotiation" take place on the OASIS as soon as practicable, as explained in Order No. 889-A.

j. Other Pricing Related Issues Not Specifically Addressed in the Final Rule

(1) Demand Charge Credits

Rehearing Requests

VT DPS argues that demand charge credits for curtailments or interruptions are needed to provide an incentive to utilities to provide high quality service. It points out that the Commission has allowed demand charge credits in the gas pipeline context (citing Tennessee Gas Pipeline Co., 71 FERC 61,399 at 62,580).[FN290]

Commission Conclusion

The Commission does not believe that electrical systems will be less reliable as a result of our initiatives on competition and open access in the Final Rule. As such, the Commission does not intend to require demand charge credits on a generic basis to encourage reliable transmission service. However, because the Commission has not mandated any particular rate design methodology under the Final Rule pro forma tariff, customers are free to argue in the compliance filing proceedings or subsequent section 205 proceedings that demand charge credits are reasonable in the context of a particular rate design method.

(2) In-Kind Transactions

Rehearing Requests

CCEM asserts that in-kind transactions in reformed power pool agreements should be abolished because of the uncertainty of valuing non-cash transactions and the potential for cross subsidizing the utilities' generation sales. It contends that a cash equivalent transaction for all formerly in-kind transactions among transmission owners is needed. ***12333**

Commission Conclusion

To satisfy CCEM's concerns, the Commission concludes that in-kind transactions must be provided on a non-discriminatory basis. The Commission recently found that in-kind transactions (i.e., transactions with payment by energy returned in kind instead of by a monetary charge) with no unbundling requirement "could hide and, thereby, mask unduly preferential terms and rates," which is precisely one of the practices that the Final Rule is intended to remedy.[FN291] While we will now require that all in-kind transactions be provided on an unbundled basis, we stress that we are not prohibiting in-kind transactions. Utilities are free to enter into contracts that contain in-kind compensation for the wholesale generation component, as long as it unbundles such transactions. Consistent with Arizona, unless the other party to the transaction contracts for transmission service under that utility's open access pro forma tariff, that utility must obtain the necessary transmission and ancillary services under the terms of its open access transmission tariff and must separately state the transmission and ancillary service prices that it will recover from the customer.

2. Priority For Obtaining Service

a. Reservation Priority for Existing Firm Service Customers

In the Final Rule, the Commission indicated that a transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon.[FN292]

Rehearing Requests

This issue is discussed in Section IV.C.5. (Reservation of Transmission Capacity for Future Use by Utility).

b. Reservation Priority for Firm Point-to-Point and Network Service

In the Final Rule, in response to concerns that network service should have a reservation priority over point-to-point service because of pricing differences, the Commission allowed utilities the opportunity to eliminate the differences in pricing between network and point-to-point services by permitting utilities to adopt point-to-point reservations as the customer load.[FN293] The Commission explained that utilities are free to propose a single cost allocation method for the two services.

In addition, the Commission provided that reservations for short-term firm point-to-point service (less than one year) will be conditional until one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. According to the Commission, these conditional reservations may be displaced by competing requests for longer-term firm point-to-point service. The Commission explained that after the deadline, the reservation becomes unconditional, and the service would be entitled to the same priorities as any long-term point-to-point or network firm service.

Moreover, the Commission explained that the Final Rule pro forma tariff does not propose point-to-point or network service with various degrees of firmness beyond the simple categories of firm and non-firm. It explained that when a customer requests firm transmission service, reservation priorities are established based first on availability, and in the event the system is constrained, based on duration of the underlying firm service request—customers may choose the "firmness" of service they want by electing to take non-firm service, or by reserving and paying for firm service.

Rehearing Requests

NRECA and TDU Systems declare that provisions making reservations for short-term firm point-to-point service conditional will not reduce the incentive to cream skim, i.e., a customer has an incentive to submit reservations for very short terms without fear of not getting service because it can always increase its request to match another longer request. They suggest an alternative: all native load, network, and long-term firm (one year or more) requests would be given priority over short-term firm requests, which would have priority over non-firm requests.

Commission Conclusion

The Final Rule has sufficiently minimized the potential for cream skimming. Further, we note that the alternative proposed by NRECA & TDU Systems has substantially been adopted in Order No. 888. Specifically, Order No. 888 provides: (1) public utilities the right to reserve existing transmission capacity needed for native load growth and network transmission customer load growth,[FN294] and (2) existing transmission customers the right of first refusal.[FN295] The only entities not covered above—potential long-term firm customers—must submit their service applications as far in advance as practicable.

c. Reservation Priorities for Non-firm Service

In the Final Rule, the Commission found that network economy purchases should have a reservation priority over non-firm point-to-point and secondary point-to-point uses of the transmission system.[FN296]

Rehearing Requests
North Jersey argues that non-firm service should be allocated on a first-come, first-served basis, and where multiple customers request service at the same time, available capacity should be allocated on a pro rata basis. It asserts that the proposed priority system based on duration of non-firm service would simply encourage non-firm customers to request service for longer durations than needed.

Commission Conclusion
We reject North Jersey's argument that the proposed priority system based on duration of non-firm service would encourage non-firm customers to request service for longer durations than needed. North Jersey ignores the fact that section 14.2 of the pro forma tariff establishes a right for eligible customers with existing non-firm reservations to match any longer term reservation before being preempted.

A related matter is discussed in Section IV.G.3.b below.

3. Curtailment and Interruption Provisions[FN297]

a. Pro-Rata Curtailment Provisions
In the Final Rule, the Commission found that curtailment on a pro-rata basis is appropriate for curtailing transactions that substantially relieve a ***12334** constraint.[FN298] The Commission explicitly allowed the transmission provider discretion to curtail the services, whether firm or non-firm, that substantially relieve the constraint.

The Commission also indicated that it would consider granting deference to an alternative curtailment method to avoid hydro spill if such a regional practice is generally accepted and adhered to across the region.

The Commission further found that under network and point-to-point service, the transmission provider may propose a rate treatment (penalty provision) to apply in the event a customer fails to curtail service as required under the Final Rule pro forma tariff and indicated that such proposals will be evaluated on a case-by-case basis on compliance.

Rehearing Requests
PA Com asserts that pro rata curtailment fails to hold native load harmless to the extent practical as required by the FPA. PA Com points out that on January 19, 1994, PJM initiated pro-rata load shedding, in part to preserve economic transactions, leaving customers in Pennsylvania without power during a record cold spell.

VA Com argues that pro rata curtailment may harm native load customers and section 206 complaints are after the fact and of little assistance to native load. VA Com argues that curtailment priority (in order of curtailment) should be: non-firm, contract firm, and then native load, and that utilities should have flexibility to curtail on a pro-rata basis within classes, subject to state curtailment policy.

Several entities argue that provision must be made for preference in curtailment priorities obtained through settlement, through payment of good and valuable consideration, or under existing transmission contracts.[FN299] Turlock argues that customers should be able to obtain a variation from the pro rata scheme if they can show that they have made either past or future investments to improve constrained facilities and that the quid pro quo for their investment is improved curtailment priority.

Allegheny asks the Commission to clarify that it did not intend to require public utilities to shed (through pro rata curtailment) native transmission load customers in order to preserve some portion of service to through system users of the grid. According to Allegheny, the FPA mandates that service reliability to franchise customers must be maintained and through-system users are not similarly situated to native transmission load customers and should not be treated the same in an emergency because through system customers can protect themselves, but native transmission load customers cannot. Allegheny adds that failure to maintain system reliability would violate section 211 of the FPA.

CCEM asserts that hard and fast priority rules are needed to prevent inconsistent rules from developing for different utilities, pools, or control areas.

Commission Conclusion

Assertions that the pro-rata curtailment provision in the tariff may harm native load customers are misplaced. The Commission clarified in the Final Rule that it was not requiring a pro-rata curtailment of all transactions at the time of a constraint, but rather curtailment of those transactions, whether firm or non-firm, that effectively relieve the constraint.[FN300] The Commission also required that such curtailments be made on a non-discriminatory basis, including the transmission provider's own wholesale use of the system. The Commission further explained that the pro-rata curtailment provision was intended to apply to situations where multiple transactions could be curtailed to relieve a constraint. Of course, if curtailment of multiple transactions is necessary, non-firm service would be curtailed prior to firm service. However, the Commission established that, in emergencies, the transmission provider had the discretion to interrupt firm service under the tariff to ensure the reliability of its transmission system.

In terms of reliability, we believe that sufficient safeguards have been established to protect native load. In particular, the transmission provider is responsible for planning and maintaining sufficient transmission capacity to safely and reliably serve its native load. Order Nos. 888 and 889 permit the transmission provider to reserve, in its calculation of ATC, sufficient capacity to serve native load.

Allegations that a utility did not curtail on a non-discriminatory basis, but instead favored a certain class of customer or type of transaction should be filed in a section 206 complaint proceeding to be reviewed on a case-specific basis. While it is true that such complaints will be processed on an after-the-fact basis, it is only on a fact-specific basis that such complaints can be fully and adequately reviewed.

Additionally, tariff section 14.7 does in fact establish that for curtailment purposes, non-firm point-to-point transmission shall be subordinate to firm transmission service and non-firm service may also be interrupted for economic reasons. However, adopting curtailment schemes based solely on classes of service, as proposed by the VA Com, is inappropriate. Specifically, VA Com's proposal to curtail all non-firm transmission transactions prior to firm transactions could exacerbate an emergency situation. For example, a curtailment could be necessary due to a constraint affecting northbound transactions. However, curtailing all non-firm transactions, including southbound transactions (or counterflows), could worsen the situation. Accordingly, the Commission believes the approach established in the Final Rule of allowing non-discriminatory curtailments of the transaction(s) that effectively relieve(s) the constraint is appropriate.

In response to CCEM's concerns regarding the potential for inconsistent rules for different utilities, pools or control areas, the Commission explained in the Final Rule that any proposed deviations from the non-price terms and conditions of the pro forma tariff, such as regional practices, must be adequately supported by the utility proposing the change.

Finally, Order No. 888 did not abrogate existing contracts;[FN301] therefore, customers with unique curtailment priorities established by pre-existing contracts would not have these priorities eliminated for the term of the existing contract.

b. Curtailment and Interruption Provisions for Non-firm Service

In the Final Rule, the Commission explained that it had clarified in the pro forma tariff that a network customer's economy purchases have a higher priority than non-firm point-to-point transmission service (citing AES Power, Inc.[FN302]).[FN303]

The Commission also revised the pro forma tariff to allow the transmission provider to curtail non-firm service for reliability reasons or to interrupt the service for economic reasons (i.e., in order to accommodate (1) a request for ***12335** firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources). The Commission further explained that a firm point-to-point customer's use of transmission service at secondary points of receipt and delivery will continue to have the lowest priority.

Rehearing Requests

For comparability, CCEM asserts that secondary receipt points should be made subordinate to other firm services,[FN304] but should have priority over non-firm point-to-point transactions. CCEM also argues that non-firm point-to-point service, once scheduled, should not be interrupted to accommodate non-firm service for a network service economy purchase.

VT DPS argues that firm flexible point-to-point service over secondary points of receipt and delivery should have a priority over non-firm point-to-point service (citing sections 14.2 and 14.7 of the pro forma tariff). It argues that this priority is necessary to reflect the fact that point-to-point customers pay for firm service and to be consistent with the treatment of network customers. VT DPS notes that in the natural gas industry the Commission has found that such priority is essential to reflect the fact that firm customers are paying for firm service (citing Order No. 636-B).

APPA asks the Commission to clarify the conditions under which the Commission will allow non-firm service to be interrupted by the transmission provider solely for economic reasons. APPA claims that this clarification is needed so as to prevent interruption of service on a discriminatory basis.

CCEM states that non-firm point-to-point transmission service does not provide the user with a specific capacity reservation, and therefore such service should bear no reservation or demand-like charges and the customer should pay a commodity-only charge only for when the service is being provided.[FN305] It contends, for example, that if a customer schedules one week of weekly non-firm transmission service and is interrupted on the second day of service, the customer should only pay for the service it used and should have no responsibility to take or to pay for service for the remainder of the week. Alternatively, it argues that if there are reservation charges and the non-firm customer pays for service on a "take-or pay basis" regardless of use, non-firm service should not be subject to being bumped once service is scheduled and power is flowing. Moreover, if the non-firm point-to-point transmission customer does pay reservation charges on a "take-or-pay basis," the non-firm reserved capacity should be tradeable in a secondary market.

Commission Conclusion

We reject CCEM's proposal to prevent scheduled non-firm transmission service from being interrupted to accommodate economy purchases for network customers. Non-firm service is provided on an interruptible basis. To the extent CCEM wishes to obtain service that cannot be interrupted to accommodate other transactions, it has the option of requesting firm service in the form of either network or point-to-point transmission service.

APPA's concerns have already been addressed by the Commission. In the Final Rule, the Commission specifically listed the economic reasons that a transmission provider could interrupt non-firm point-to-point transmission to include:

accommodat[ing] (1) a request for firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources.[FN[306]]

CCEM's arguments are misplaced in that they focus on the specific rate (including any potential credits for service interruption) that utilities may propose for non-firm point-to-point transmission service. Order No. 888 did not mandate any pricing methodology to be used for non-firm point-to-point transmission service. Rather, the Commission established the minimum non-price terms and conditions necessary to ensure comparable service. As the Commission explained in the Final Rule, utilities are free to propose any rates for non-firm point-to-point transmission in a section 205 filing consistent with the Commission's Transmission Pricing Policy Statement.[FN307] However, the Commission will evaluate the appropriateness of such proposed rates against the non-price terms and conditions established in the pro forma tariff or other non-price terms and conditions proposed and fully supported by the utility.[FN308]

The Commission has previously addressed VT DPS' point.[FN309] Non-firm point-to-point customers pay for non-firm service as their service. Firm point-to-point customers, on the other hand, contract and reserve a specified amount of service over designated points of receipt and delivery. The Commission permitted these firm point-to-point customers to use secondary non-firm service (from points of receipt/delivery other than those designated in their service agreement) on an as-available basis at no additional charge. Because the firm point-to-point customers taking secondary non-firm are accorded this scheduling flexibility at no additional charge, they are properly accorded a lower priority than stand alone, non-firm transmission. In contrast, network customers are responsible for paying for a percentage of total system transmission costs in order to serve their designated network loads whether the energy is from designated network resources or from non-designated resources on an as-available basis.[FN310] Because the network customer pays a load-ratio share of total transmission costs, it receives a higher priority. Significantly, if any firm point-to-point customer wants to avail itself of the higher priority associated with economy energy purchases under the network tariff, it is free to do so by undertaking the cost responsibilities associated with network service.

Finally, in response to VT DPS, we note that we have chosen different approaches in the electric and natural gas areas. In this regard, we recognize that there is a trade-off between encouraging tradable capacity rights versus maximizing revenues that can be credited against the transmission provider's costs of providing transmission service. On the electric side, fully developed transmission capacity trading rights simply do not exist at this time, and so we have chosen to emphasize an approach that maximizes revenues to be credited to transmission customers. However, we will continue to evaluate our approach in the context of any future transmission rate proposal that is based on the concept of tradable capacity rights. ***12336**

4. Reciprocity Provision

In the Final Rule, the Commission concluded that it was appropriate to require a reciprocity provision in the pro forma tariff.[FN311] The Commission explained that this provision will be applicable to all customers, including non-public utility entities such as municipally-owned entities and RUS cooperatives, that own, control or operate interstate transmission facilities and that take service under the open access tariff, and any affiliates of the customer that own, control or operate interstate transmission facilities.

The Commission developed a voluntary safe harbor procedure under which non-public utilities would be allowed to submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. The Commission explained that if it finds that a tariff contains terms and conditions that substantially conform or are superior to those in the Final Rule pro forma tariff, it will deem it an acceptable reciprocity tariff and require public utilities to provide open access service to that non-public utility.

If a non-public utility chooses not to seek a Commission determination that its tariff meets the Commission's comparability standards, the Commission declared that a public utility could refuse to provide open access transmission service. However, any such denial must be based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.

In support of its decision to adopt a reciprocity provision, the Commission explained that it was not requiring non-public utilities to provide transmission access, but was conditioning the use of public utilities' open access services on an agreement to offer open access services in return. The Commission noted that non-public utilities can choose not to take service under public utility open access tariffs and can instead seek voluntary service from the public utility on a bilateral basis.

The Commission further explained that the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system. However, the Commission recognized that Congress has determined that certain entities in the bulk power market can use tax-exempt financing by issuing bonds that do not constitute "private activity bonds"[FN312] or by financing facilities with "local furnishing" bonds.[FN313] The Commission stated that it was not its purpose to disturb Congress' and the IRS's determinations with respect to tax-exempt financing. Therefore, the Commission clarified that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities.[FN314]

With respect to local furnishing bonds, which are available to a handful of public utilities, the Commission noted that Congress, in section 1919 of the Energy Policy Act, amended section 142(f) of the Internal Revenue Code to provide that a facility shall not be treated as failing to meet the local furnishing requirement by reason of transmission services ordered by the Commission under section 211 of the FPA if "the portion of the cost of the facility financed with tax-exempt bonds is not greater than the portion of the cost of the facility which is allocable to the local furnishing of electric energy."[FN315] So that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime, the Commission required any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff a similar provision that it will not contest the issuance of an order under section 211 of the FPA requiring the provision of such service, and will, within 10 days of receiving a written request by the applicant, file with the Commission a written waiver of its rights to a request for reciprocal service from the applicant under section 213(a) of the FPA and to the issuance of a proposed order under section 212(c).

In addition, the Commission limited the reciprocity requirement to the applicant and corporate affiliates. The Commission explained that if a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, would be required to offer transmission service. However, if a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its G&T cooperative) must offer reciprocal transmission service over any interstate transmission facilities that it may own, control or operate.

Furthermore, the Commission explained that a non-public utility, for good cause shown, may file a request for waiver of all or part of the reciprocity requirement.

The Commission also explained that the reciprocity requirement will apply to any entity that owns, controls or operates interstate transmission facilities that uses a marketer or other intermediary to obtain access. The Commission added that it would apply the same criteria to waive the reciprocity condition for small non-public utilities as for small public utilities.

Rehearing Requests

Reciprocity Provision—Public Power Position

A number of public power entities argue that the reciprocity provision should be eliminated because the Commission cannot require indirectly what it cannot require directly.[FN316] Several other public power entities add that the reciprocity obligation is beyond the jurisdiction of the Commission because the transmission obligations of non-public utilities (e.g., municipal utilities) are established and limited to those required by sections 211 and 212 of the FPA.[FN317] Tallahassee asserts that the Commission's conditioning approach has the effect of excluding an entire class of transmission customer from open access, i.e., those unable to grant reciprocal service. This, Tallahassee asserts, is discriminatory and contrary to the purpose of the Final Rule and the requirements of sections 205, 206 and 212 of the FPA. TANC argues that the Commission does not have the discretion to grant or withhold open access transmission on the condition that the customer consent to doing something that the Commission admits it cannot directly order: "The Commission has never 'conditioned' its duty to allow only just and reasonable rates on any action by the customer." (TANC at 16).

A number of entities challenge the Commission's assertion that the reciprocity requirement for non-public *12337 utilities is voluntary.[FN318] Dairyland contends that the alternative of seeking a bilateral agreement is illusory—even if it could be obtained—because Order No. 888 provides that any bilateral wholesale coordination agreement executed after July 9, 1996 will be subject to open access requirements. Dairyland argues that the phrase "subject to open access requirements" presumably would include the reciprocity requirement for non-public utilities.

AEC & SMEPA assert that there is no record support for the contention that non-public utilities are responsible for closed systems or that such systems, if any, have an impact on the market.

NRECA asserts that if the reciprocity provision is retained, the Commission should "modify its terms to incorporate the statutory standards and protections which FPA sections 211 and 212 contain."[FN319]

Umatilla Coop asks the Commission to clarify that distribution cooperatives will not become subject to the reciprocity requirements merely because they purchase power from affiliated cooperatives that are acting as power marketers. TDU Systems assert that a cooperative should not have to render reciprocal service if it would interfere with its ability to obtain RUS loan financing.

TAPS declares that the transmission provider alone should not have access to third-party systems through reciprocity. It maintains that the utility's long-term transmission customers should also be afforded access to those third-party systems so that the transmission provider does not have a competitive advantage. TAPS argues that a third-party should be required to have an open access tariff available.

Reciprocity Provision—Utility Position

A number of utilities argue that the exemption from reciprocity for distribution cooperatives should be eliminated.[FN320] EEI and Montana-Dakota Utilities assert that G&Ts could eliminate their reciprocity obligation by selling or transferring their transmission facilities to their distribution owner/members. Southwestern argues that the exception for distribution cooperatives puts public utilities at a competitive disadvantage in that distribution cooperatives can use a public utility's system to compete with the public utility, but a public utility cannot use the distribution cooperatives' systems to compete to sell power to their customers.[FN321] It adds that the exception allows distribution cooperatives to hide behind shell G&Ts. For example, Southwestern argues that Golden Spread Electric Cooperative is a shell G&T because it owns only small amounts of facilities. It concludes that reciprocal access may become especially important if a state implements a retail access plan because section 211 cannot be used to obtain transmission for retail access over a distribution cooperative's system.

Southern claims that cooperatives have argued in courts and in Congress that a G&T cooperative and its distribution cooperative owners are unified economic interests in which the interest of the whole is equal to the sum of the parts, and that federal courts have upheld this view (citing one case—City of Morgan City v. South Louisiana Electric Cooperative Ass'n, 49 F.3d 1074 (5th Cir. 1995) (Morgan City)).

EEI claims that clarification of certain aspects of reciprocity is needed: (1) public utilities may not be able to determine if reciprocal service is comparable because non-public utilities do not have to provide Form 1 data, and thus non-public utilities should be required to submit additional data; (2) non-public utilities should be required to functionally unbundle, charge rates to themselves and others that reflect the cost of using the system themselves, comply with the standards of conduct, and establish an OASIS; (3) non-public utility members of an RTG should be required to offer reciprocal service comparable to that provided by public utility members; and (4) a non-public utility should be required to provide all services it is reasonably capable of providing. Carolina P&L adds that a customer should be required to provide the full panoply of transmission services that it is capable of providing because the customer has a right to take any type of service from the transmission provider even though it may only choose one particular service.

Tucson Power asks the Commission to clarify how it will determine the comparability of a non-public utility's tariff. It asserts that first, under the safe harbor option, the Commission should clarify (1) that non-public utilities must comply with the Commission's rules of practice and procedure, and (2) how it will determine that the rates, terms and conditions of the reciprocal service are comparable to the service the non-public utility provides itself (Tucson Power argues that this could require submittal of data comparable to that contained in Form 1). Second, the Commission should eliminate the option that would require the public utility to determine whether the request by the non-public utility is consistent with the tariff. Finally, under the RTG option, the Commission should clarify that the evidentiary requirements for non-public utilities that are members of an RTG will be the same as for non-public utilities using the safe harbor procedure, i.e., any disputes regarding compliance should be resolved by the Commission, not the RTG.

A number of utilities assert that the Commission should not limit the right to obtain reciprocity only to the public utility that provides the transmission service because power could actually flow over other public utilities' transmission lines. They argue that the Commission should ensure that open access transmission is as widely available as possible.[FN322] EEI asserts that Federal power marketing agencies, including BPA, should be required to provide comparable open access transmission.

Oklahoma G&E argues that Order No. 888 violates the Constitution's equal protection principles because it does not require universal open access. It asserts that the Commission has created an arbitrary distinction between classes of utilities that is unrelated to the Commission's objective and therefore is constitutionally invalid. Oklahoma G&E contends that the proper approach is to proceed under EPAct for all transmitting utilities on a case-by-case basis.

Detroit Edison asks the Commission to clarify that the supplier and the recipient of power are direct beneficiaries and must be considered transmission customers for reciprocity purposes. Otherwise, Detroit Edison contends, parties from jurisdictional transmission transactions may be able to evade reciprocity.

Reciprocity Provision—Other Arguments

CCEM argues that reciprocity should be expanded to require a transmission customer obtaining open access service also to provide open-access transmission service to all eligible customers. Otherwise, CCEM maintains, transmission owners will be able to penetrate into wholesale markets controlled by non-public utilities, but power marketers will not. ***12338**

CCEM asks the Commission to clarify that when a non-public utility obtains open access from a power pool, member of a power pool, or parties to some form of bilateral coordination agreement, its reciprocity obligation extends to all eligible customers, including all members of the pool or parties to the agreement.

Commission Conclusion

We continue to believe that it is appropriate to condition the use of public utility open access tariffs on the agreement of the tariff user to provide reciprocal access to the transmission provider. No eligible customer, including a non-public utility, that takes advantage of non-discriminatory open access transmission tariff services should be allowed to deny service or otherwise discriminate against the open access provider. As we explained in the Final Rule, [n]on-public utilities, whether they are selling power from their own generation facilities or reselling purchased power, have the ability to foreclose their customers' access to alternative power sources, and to take advantage of new markets in the traditional service territories of other utilities. While we do not take issue with the rights these non-public utilities may have under other laws, we will not permit them open access to jurisdictional transmission without offering comparable service in return. We believe the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system.[FN[323]]

Contrary to arguments raised on rehearing, we are not requiring non-public utilities to provide transmission access. Instead, we are conditioning the use of public utility open access tariffs, by all customers including non-public utilities, on an agreement to offer comparable (not unduly discriminatory) services in return.[FN324] It would not be in the public interest to allow a non-public utility to take non-discriminatory transmission service from a public utility at the same time it refuses to provide comparable service to the public utility. This would restrict the operation of robust competitive markets and would harm the very ratepayers that Congress has charged us to protect. Very simply, we refuse to take a head-in-the-sand approach and order a remedy for undue discrimination that will permit the beneficiaries of the remedy to engage in unduly discriminatory actions.

Moreover, non-public utilities are free to seek from a public utility a waiver of the open access tariff reciprocity condition. We note that this is a modification of our statements in Order No. 888, in which we said that non-public utilities could seek a voluntary offer of transmission service from a public utility on a bilateral basis. Since the time Order No. 888 issued, we have concluded that except in unusual circumstances, public utility services should be provided pursuant to the open access tariff and not pursuant to separate bilateral agreements.[FN325] This applies to all customers, including non-public utilities. Therefore, rather than requesting a bilateral agreement in order to avoid the reciprocity condition, non-public utilities instead may ask a utility for a waiver of the reciprocity condition in the utility's open access tariff. We disagree with Dairyland that this type of alternative approach is illusory. If the public utility chooses voluntarily to grant a waiver, the reciprocity condition would not apply.

We reject NRECA's request that we incorporate in the reciprocity condition the statutory standards and protections of FPA sections 211 and 212. NRECA states on rehearing that mandated services to third parties would endanger cooperatives' ability to provide service to members, or increase members' costs. It further states that sections 211 and 212 provide substantive protections to ensure continued service to the transmitting utility's own customers, and to avoid their subsidization of services to third parties. NRECA appears to believe that these substantive protections are not provided outside the context of sections 211 and 212. We disagree. We believe the protections that NRECA is seeking are contained in the pro forma tariff and, as required by section 6 of the tariff, the non-public utility must offer its service on similar terms and conditions.[FN326]

We also reject requests that we not grant the exception to reciprocity provided in the Final Rule for distribution cooperatives and joint action agencies. We continue to believe that if a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, should be required to offer transmission service.[FN327] Without a corporate affiliation between G&T cooperatives and their member distribution cooperatives, we do not believe it is appropriate to apply the reciprocity condition to the member distribution cooperatives. To do so would result in the member distribution cooperatives being bound by their G&T cooperatives.[FN328]

Carolina P&L has brought to our attention a possible misunderstanding as to the meaning of comparable transmission service that a non-public utility must agree to provide as a condition of using an open access tariff. Because a non-public utility may choose any type of service from a public utility transmission provider that the transmission provider provides or is capable of providing, we clarify that a non-public utility seeking to take service under the transmission provider's open access tariff must likewise agree to offer to provide the transmission provider any service that the non-public utility provides or is capable of providing on its system in order to satisfy reciprocity. We note that in the Final Rule we explained that "[a]ny public utility that offers non-discriminatory open access transmission for the benefit of customers should be able to obtain the same non-discriminatory access in return."[FN329] In this regard, because a public utility must have an OASIS and a standard of conduct for employee separation, so must a non-public utility that seeks open access transmission from a public utility.[FN330]

At the same time, however, we deny requests to expand the reciprocity condition.[FN331] Although we believe that non-public utilities should provide open access transmission as a matter of policy, to require non-public utilities to offer transmission service to entities other than the public utility transmission providers increases the chances that they could lose tax-exempt status. Accordingly, we have adopted a policy that recognizes the statutory tax restrictions placed on non-public utilities but also balances the fundamental unfairness of requiring a utility to make its facilities available to someone who could use that access to the competitive disadvantage of the utility. Ultimately the public interest is best served by nationwide open access and, if the tax issue is favorably resolved, we may revisit the matter.

Moreover, in response to Detroit Edison, we take this opportunity to clarify that reciprocity would apply to a wholesale purchaser if a generation seller obtains transmission service from a public utility to sell to such purchaser and such purchaser owns, operates or controls interstate transmission facilities. The same would be true where the seller owns, operates and controls interstate transmission facilities and the buyer arranges for the transmission service. Just as with marketers or other intermediaries, we do not intend to allow reciprocity to be defeated simply on the basis of whether the seller or buyer requests transmission. Such a result would elevate form over substance.

With respect to TDU System's assertion that reciprocal service should not have to be rendered if it would interfere with RUS loan financing, we note that we have already indicated that reciprocal service need not be provided if tax-exempt status would be jeopardized. If TDU Systems is arguing that we should not require reciprocal service if RUS attaches such a condition in its regulation of RUS-financed cooperatives, we reject such an argument. Such cooperatives have the option to seek bilateral service agreements.

We reject EEI's and Tucson Power's argument that non-public utilities must provide Form 1 data in order to provide comparable service. The Form 1 data would be relevant only if the Commission were setting non-public utilities' rates. Such a detailed review is not necessary, however. See Santee Cooper, 75 FERC 61,209 (1996). Similarly, there is no need to have non-public utilities follow our Rules of Practice and Procedure to satisfy reciprocity.

Rehearing Requests

Safe Harbor/Waiver Provisions

NRECA states that the following issues related to safe harbor status and declaratory order requests need clarification: (1) under what statutory authority is the Commission considering such petitions? (2) what rights do non-public utilities have to obtain review of Commission determinations with which they disagree? (3) how closely will a reciprocal tariff have to conform to Order No. 888 to win approval? (4) will non-public utilities have to pay the standard fee (now $11,550) with a declaratory order petition?[FN332] and (5) will the Commission allow non-public utilities to include a stranded cost recovery provision similar to section 26 of the pro forma tariff?[FN333]

Oglethorpe asserts that the Commission should not use these procedures to assert jurisdiction over non-public transmitting utilities. Dairyland contends that requiring non-public utilities to invoke declaratory order or waiver proceedings just to assert the clear statutory protections contained in sections 211 and 212 is unwarranted.

TANC declares that the safe harbor provisions do not cure the problems created by reciprocity. It argues that the safe harbor provision expands the transmission access that must otherwise be offered by non-public utilities, i.e., rather than just providing reciprocal service to the transmission provider, under the safe harbor provision, the non-jurisdictional entity must offer open access to any eligible customers.

Blue Ridge alleges that the safe harbor and waiver provisions face practical administrative problems. It asserts that a waiver itself will result in disputes and that the application of the waiver principle to non-public utilities is based on questionable statutory authority. It requests that the Commission add the following language to section 6 of the tariff: "If the Transmission Customer is a non-public utility, the Transmission Provider must demonstrate a need for transmission service from such entity." (Blue Ridge at 39).

TAPS asks that the Commission accord the filing of a waiver application by a small non-public utility system, or inclusion in an application of a sworn statement of inapplicability, the same protections afforded larger non-public utility systems that file under the safe harbor mechanism.

Arkansas Cities ask the Commission to clarify that "utilities like Arkansas Cities' members, which do not operate a control area, do not own 'transmission' facilities and primarily purchase energy for resale at retail are not subject to the transmission reciprocity condition contained in Order 888, and are also not required to file a request for a waiver from the requirements of Order 888 and 889." (Arkansas Cities at 18-19)

SWRTA and NWRTA ask the Commission to clarify that RTGs have the authority to issue limited waivers of the reciprocity requirements of Order Nos. 888 and 889 to qualifying non-public utility members of RTGs, and that the Commission will accord deference to an RTG's determination with respect to a non-public utility member's request for waiver of, or exemption from, these requirements.[FN334] They note that SWRTA's bylaws have a Commission-approved waiver process and disputes would go to arbitration or to the Commission.

Southern and EEI argue that public utilities should have a parallel "safe harbor"—the right to seek a declaratory order as to whether the transmission service being offered by a non-public utility satisfies its reciprocity obligation.

Tallahassee asks that the Commission clarify the good faith assertion a public utility must make that the non-public utility has not met the reciprocity requirements. It asserts that the section 211 good faith request rules form an appropriate standard by which to measure a good faith assertion.

Commission Conclusion

Several entities raise procedural and jurisdictional concerns with respect to our safe harbor and waiver provisions. At the outset, we emphasize that this Commission does not have jurisdiction over non-public utilities under sections 205 and 206 and that the safe harbor mechanism and waiver provisions do not, and indeed cannot, give us such jurisdiction. Rather the safe harbor and waiver procedures are voluntary means for non-public utilities to obtain a Commission determination that they meet the reciprocity condition in the open access tariffs and thereby avoid ***12340** potential delays or denials of open access service based on allegations that the transmission requestor does not meet reciprocity. In Santee Cooper, issued subsequent to the Final Rule, the Commission recognized that it lacks jurisdiction under sections 205 and 206 over transmission rates, terms and conditions offered by non-public utilities, but explained that it has the authority to evaluate non-jurisdictional activities to the extent they affect the Commission's jurisdictional responsibilities.

We clarify that non-public utilities that disagree with a Commission determination are free to request rehearing of a Commission order, as occurred in Santee Cooper. If aggrieved by the Commission's final order, they may appeal under section 313 of the FPA. Also, with respect to the filing fee a non-public utility entity would have to pay in making a declaratory order request, the Commission in Santee Cooper explained that its regulations specifically exempt states, municipalities and anyone who is engaged in the official business of the Federal Government from filing fees.[FN335] Because of the nature of the safe harbor and waiver provisions, we will also waive the filing fee for declaratory orders for all other non-public utilities in these circumstances.

As to the question of how closely a reciprocal tariff will have to conform to Order No. 888, the Commission determined in Santee Cooper that:

As part of its compliance filing * * * the Authority must submit a single tariff that conforms to the Open Access Rule pro forma tariff.[FN[336]]

The Commission further explained that "[t]he Open Access Rule requires that reciprocity tariffs contain terms and conditions which substantially conform or are superior to those in the Open Access Rule pro forma tariff."[FN337] We clarify, however, that in that case the utility chose to offer an open access tariff, whereas Order No. 888 provides, as a condition of service, that reciprocal access be offered to only those transmission providers from whom the non-public utility obtains open access service. Therefore, a non-public utility may so limit the use of any voluntarily offered tariff, as long as the tariff otherwise substantially conforms to the pro forma tariff. We also note that non-public utilities are free to enter into bilateral agreements to satisfy the reciprocity condition. With respect to such bilateral reciprocal agreements, we must leave these agreements to case-by-case determinations. Which terms and conditions may be necessary for a non-public utility to provide reciprocal service to the

public utility in a bilateral agreement is necessarily a fact-specific matter not susceptible to resolution in a generic rulemaking proceeding. Additionally, we clarify that non-public utilities may include stranded cost recovery provisions in any reciprocity tariffs that they may file.[FN338]
In response to TANC's concern that the safe harbor provision expands the transmission access that must otherwise be offered by non-public utility entities, and Blue Ridge's concern that the safe harbor and waiver provisions raise practical administrative problems, we emphasize that both of these procedures are purely voluntary and a non-public utility can avoid any perceived problems simply by not taking part in either process. We note that several entities have voluntarily availed themselves of these procedures without any apparent hardships.[FN339]

Arkansas Cities' various waiver requests are best addressed on a case-by-case basis that permits a full airing of the factual circumstances surrounding each entity seeking a waiver. As we explained in a recent order, "the Commission will not address waiver requests in a generic rulemaking proceeding, but will require entities seeking waiver of all or part of Order Nos. 888 and 889 to submit separate, fact-specific requests. * * *"[FN340]

EEI's and Southern's request that public utilities be provided a parallel "safe harbor" (i.e., the right to seek a declaratory order as to whether the transmission service being offered by a non-public utility satisfies its reciprocity obligation) is denied. In the Final Rule, we explained that a public utility may refuse to provide open access transmission service to a non-public utility if its denial is based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.[FN341] Moreover, a public utility can file a petition to terminate transmission service if a non-public utility is violating the reciprocity condition of its open access service agreement with the public utility.[FN342]

In response to SWRTA and NWRTA's request to clarify that RTGs have the authority to issue limited waivers of the reciprocity conditions of the Order No. 888 pro forma tariffs, we recognize that RTGs have procedures in place to resolve disputes that may arise concerning a non-public utility member's request for service from a public utility member. Because RTGs have these dispute resolution procedures in place, we clarify that RTGs, which are in themselves reciprocal voluntary arrangements, may determine whether to apply reciprocity between and among member public utilities and member non-public utilities, subject to the RTG dispute resolution procedures authorized by this Commission.

Rehearing Requests

Retail Wheeling
Dairyland contends that the Commission improperly requires a non-public utility to provide retail wheeling if it uses the open access tariff of a public utility that allows retail access either voluntarily or as part of a state-mandated program.

Commission Conclusion
Contrary to Dairyland's contention, nothing in the Final Rule requires a non-public utility to provide retail wheeling. Section 212(h) of the FPA explicitly prohibits the Commission from ordering retail transmission directly to an ultimate consumer. If a non-public utility offers reciprocal service, its tariff would have to include the same explicit provision contained in the pro forma tariff, which states that an eligible customer cannot obtain transmission that would violate section 212(h) of the FPA, unless pursuant to a state program that requires the transmission provider to offer such wheeling.

Rehearing Requests

OASIS
Southern argues that the Commission should explicitly require that non-public utilities must comply with Order No. 889 as part of the reciprocity obligation.

Commission Conclusion
We agree with Southern and, as discussed above, absent a waiver, will ***12341** require non-public utilities to comply with Order No. 889 as part of the reciprocity obligation.

Rehearing Requests

Foreign Entities
In the Open Access Rule, we decided that a foreign entity that otherwise meets the eligibility criteria should be able to obtain service under a United States public utility's open access tariff. However, like United States non-public utilities (which also are not under our section 205-206 jurisdiction), a foreign entity that owns or controls transmission facilities and that takes transmission service under a United States public utility's open access tariff must comply with the reciprocity provision in the tariff.[FN343] The reciprocity provision ensures that when a public utility provides service under its open access tariff to a transmission-owning entity that is not subject to the open access requirement, the public utility will be able to receive service in turn from that entity. In our discussion of the reciprocity provision, we pointed out that if a non-jurisdictional entity that owns or controls transmission does not wish to provide service to the public utility, it can choose not to use the public utility's open access tariff and can instead seek voluntary service from the public utility on a contractual basis.[FN344]

On rehearing, Ontario Hydro argues that the Commission has "unilateral[ly] impos[ed]" the reciprocity requirement on foreign entities in violation of the North American Free Trade Agreement (NAFTA).[FN345] It declares that

[u]nder the principle of national treatment, the citizens of each party to NAFTA * * * are allowed the same market access within another treaty party's market as is provided to the citizens of such other party. A party to these agreements cannot withhold access to its market by conditioning it upon receipt of equal access into the market of another party, because the result would be market access less favorable for the other party * * * than that accorded the party's own citizens.[FN346]
Ontario Hydro claims that the Open Access Rule "makes open access the law of the land for wholesale transmission service within the United States * * *" and that Canadian entities are thus entitled to such access on an unconditional basis.[FN347] Next, it accuses the Commission of trying to "coerce" Canada to "conform its market access policy" to United States policy and of "impos[ing] U.S. regulatory policies" on Canadian markets.[FN348] Finally, Ontario Hydro argues that even aside from the NAFTA issue, under the FPA the Commission does not have jurisdiction over foreign entities and thus cannot require reciprocity.

Commission Conclusion
We disagree with Ontario Hydro's claim that NAFTA's national treatment principle requires us to allow a Canadian transmission-owning entity (or its corporate affiliate) to take advantage of a United States public utility's open access tariff—a tariff we have required the utility to adopt—while simultaneously refusing to allow the United States utility to use the Canadian entity's transmission facilities. NAFTA's national treatment principle requires that each signatory "accord national treatment to the goods" of other signatories in accordance with Article III of the General Agreement on Tariffs and Trade (GATT).[FN349] National treatment means that the United States "must not discriminate between foreign and domestic energy on the basis of nationality * * *" and that Canadian electricity must be treated "no less favorabl[y] than U.S. electricity, under all U.S. laws and rules respecting the sale, * * * distribution, and use of * * * electricity." Thus, this Commission must accord Canadian energy supplies treatment that is no less favorable than the treatment accorded United States supplies.[FN350] Ontario Hydro's interpretation, however, would twist this principle into a requirement that Canadian entities be treated better than United States entities, including United States non-public utilities that are subject to the reciprocity condition.[FN351]

Under Order No. 888, all public utility open access tariffs contain a reciprocity condition that applies to all users of the tariff within the United States, including United States non-public utilities, unless the condition is waived either by the Commission or the public utility provider. Under the reciprocity condition, non-public utilities do not have to offer an open access tariff (i.e., a tariff that offers transmission service to any eligible customer), but rather must offer comparable transmission services only to those transmission providers whose open access tariffs the non-public utility uses.[FN352] The same condition applies to foreign utilities. Thus, Ontario Hydro is in plain error in arguing that application of the reciprocity condition to foreign entities would result in less favorable treatment than that accorded to United States citizens. Ontario Hydro's reading of NAFTA would place transmission-owning Canadian entities (or their corporate affiliates) in a better position than any domestic entity; not only would Canadian entities not be subject to the open access requirement, but, unlike domestic non-public utilities, they would be able to use the open access tariffs we have mandated without providing any reciprocal service. Ontario Hydro has cited no precedent demonstrating that NAFTA imposes such an unreasonable requirement.[FN353]

Moreover, we are not "coercing" Canada into adopting our policies or "imposing" open access on Canadian entities; we are simply placing the same condition on a Canadian entity's use of a United States utility's open access tariff as on a domestic non-public utility's use of that tariff. However, consistent with the approach we have taken in other contexts involving foreign utilities seeking to transact in United States electricity markets, we are amenable to a variety of approaches for Canadian utilities to meet the reciprocity condition.[FN354]

Ontario Hydro is also wrong in its claim that even aside from NAFTA, we lack authority under the FPA to require reciprocity when a foreign entity wishes to use a domestic utility's open access tariff. Just as we are not asserting jurisdiction over domestic non-public utilities under sections 205 or 206 of the FPA, we also are not asserting jurisdiction over foreign entities. Rather, we are simply placing the same reasonable and fair condition on both types of entities' uses of the transmission ordered in the Final Rule.[FN355]

Rehearing Requests

Unconstitutional as Applied to NE Public Power District

NE Public Power District asserts that the reciprocity provision as applied to NE Public Power District (a public corporation and political and governmental subdivision under Nebraska law) is unconstitutional. It argues that reciprocity would intrude into the sovereignty of Nebraska and would negate the decision of Nebraska's citizens to use their own governmental institutions to provide electric service. Moreover, contrary to the Commission's assertion, NE Public Power District states that it does not have a real choice in deciding whether to use the transmission service of public utilities. Because it is beyond the power of Congress to compel Nebraska to adopt a federally prescribed program for providing its citizens with electric utility services, NE Public Power District argues that it must follow that a federal agency lacks the constitutional and statutory authority to compel a Nebraska state instrumentality to adopt a FERC-drafted tariff and to modify its contracts.

NE Public Power District states that section 201(f) of the FPA exempts state-owned utilities from the jurisdiction of the Commission and that sections 211-213 are the exclusive means by which the Commission can require non-public utilities to perform involuntary transmission service. It asserts that the Commission should exempt publicly-owned utilities from application of the Final Rule and notes that virtually all non-public utility entities are, or soon will be, voluntary participants in power pools, RTGs, or other similar organizations. Thus, NE Public Power District argues that there is no compelling public interest to require these entities now to submit to the reciprocity provision.

In addition, NE Public Power District argues that compliance would conflict with Nebraska law and bond covenants, i.e., Nebraska law, for example, does not permit a public entity to agree in advance of a dispute to submit to binding arbitration. NE Public Power District states that it is bound by a bond covenant that prohibits it from rendering service free of charge and requires that a customer's default must be cured within a specific time. It also argues that these requirements are in conflict with section 7.3 of the pro forma tariff.

Commission Conclusion

Under the Supremacy Clause of the Constitution, Nebraska law cannot and does not override this Commission's authorities and responsibilities under the FPA. Rather, this Commission has exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities, including reciprocity conditions contained in the tariffs of public utilities. Nothing in Order No. 888 compels Nebraska to adopt a "federally prescribed program." While we do not have full jurisdiction over non-public utilities,[FN356] our actions in regulating jurisdictional matters may impact those who wish to use jurisdictional services or to enter into agreements with public utilities. The Commission's obligation is to ensure that public utilities' services are just and reasonable and not unduly discriminatory or preferential and non-public utilities can choose to comply or not regarding matters within our exclusive jurisdiction. Moreover, as we explained above, NE Public Power District can seek waiver of the reciprocity condition on a case-by-case basis.

Rehearing Requests

QF Position

American Forest & Paper asks the Commission to clarify that QFs are exempted from the reciprocity requirement or, in the alternative, grant them a blanket waiver. It states that QFs are not allowed to provide transmission service for third parties. Moreover, it asserts that there are unlikely to be many requests for transmission service over a QF's interconnection line and such cases should be handled on a case-by-case basis.

Commission Conclusion

We will not grant QFs an exemption from the reciprocity condition or grant them a blanket waiver, but will address this issue on a case-by-case basis if and when it arises. Because most QFs own little transmission, it is not likely that they will be asked to provide reciprocal service.

Furthermore, in a proceeding involving a QF, we explained that use of a QF's transmission line by a non-QF would not affect its QF status:

It would not fail the ownership test for QF status because, consistent with the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA), the Oxbow Geothermal facility would continue to be "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)." 16 U.S.C. §796(18)(B)(1994).[FN[357]]

If a QF that owns, controls or operates interstate transmission facilities seeks open access transmission from a public utility, it must agree to provide reciprocal service to that public utility. Of course, the QF could file a waiver request in a separate proceeding, as set forth in the Final Rule and clarified in a subsequent order.[FN358]

Rehearing Requests

Tax-Exempt Financing Issues

Reciprocity and Private Activity Bonds

EEI asks the Commission to require non-public utilities claiming that their tax status is a bar to granting reciprocity to substantiate such claim in a safe harbor proceeding and to take reasonable measures to request the IRS to allow them to provide reciprocal service while retaining their tax status. If the Commission decides not to require a safe harbor proceeding, EEI requests that the Commission require non-public utilities to substantiate their tax concerns and to demonstrate to each public utility from which they seek service that they are actively pursuing ***12343** the issue with the IRS.[FN359] It also urges that the Commission require any request for exemption from the reciprocity requirement that is based on jeopardy to tax-exempt status be filed with the Commission as part of a request for declaratory order in a safe harbor proceeding. Moreover, it requests that the Commission require a non-public utility to specifically identify the facilities it cannot use without jeopardizing its tax-exempt financing and to provide copies of, and specifically reference the tax provisions in, the related financing agreements that embody this restriction.

Centerior asks that the Commission condition receipt of open access transmission service by municipal utilities upon the elimination or mitigation of tax subsidies and regulatory inequities. Southern maintains that tax-exempt status can remain undisturbed if non-public utilities do not seek open access transmission service from public utilities. Thus, Southern asserts, non-public utilities can weigh the benefits of transmission service under the Final Rule against the potential threat to their tax benefits, and make the choice that serves their best interest. At a minimum, it argues, the Commission should await the determinations of the IRS before finalizing this aspect of the reciprocity provision, rather than confer yet another unique benefit on non-public utilities.[FN360]

CAMU asks that the Commission defer reciprocity obligations until the IRS has clarified the status of private use limitations within the context of transmission access. Otherwise, CAMU asserts, innocent investors could suffer penalties because the Commission moved too quickly on this sensitive issue.

Local Furnishing Bonds

Local Furnishing Utilities and ConEd state that section 5.1 of the pro forma tariff applies to "Transmission Service," which is defined in section 1.48 to include point-to-point service, but not network service. They ask the Commission to clarify that the phrase "transmission service" also applies to network service.

Local Furnishing Utilities and ConEd ask that the Commission confirm that all costs associated with the loss of tax-exempt status, including defeasing, redeeming, and refinancing tax-exempt bonds, will be considered costs of providing transmission that must be borne by the customer for whom the transmission is provided. They state that defeasance and refinancing costs are just as attributable to the particular transmission service causing such defeasance or redemption as the costs of expanding the system are attributable to the service that cause the need for such expansion. They ask that the Commission clarify that a transmission provider may include in its tariff a provision permitting the recovery of such costs, even if a filing under section 205 of the FPA is required. ConEd asserts that if a customer does not want to pay costs associated with the loss of tax-exempt status on the bonds, the Commission should allow the transmission provider to decline to provide the requested service.

Local Furnishing Utilities and ConEd also assert that section 5.2 of the pro forma tariff should be clarified to state that issuance of a section 211 order by the Commission is a condition precedent to the provision of transmission service. Local Furnishing Utilities states that there is a question whether the Commission should insist on waiver of the issuance of a proposed order under section 212(c). According to Local Furnishing Utilities, the negotiations that normally would follow the issuance of a proposed order are likely to provide the only opportunity to demonstrate and review the costs associated with the loss of tax-exempt status.

Local Furnishing Utilities and ConEd assert that sections 5.1 and 5.2(i) of the pro forma tariff improperly limit the safe harbor protection of section 1919 of EPAct to transmission providers that financed "transmission facilities" with local furnishing bonds. Because of this, they assert, the safe harbor is not available to ConEd, all of whose local furnishing bonds have been used to finance its distribution system. They argue that section 5.1 should apply to service that would jeopardize the tax-exempt status of bonds that finance distribution or generation, as well as transmission, facilities. NE Public Power District contends that section 5.2(ii) should be amended "to make it clear that interim service need not be begun if rendering the service would endanger the tax-exempt status of the provider's bonds, unless the customer agrees to bear the financial consequences of such loss of tax-exempt status and has the wherewithal to do so." (NE Public Power District at 22-23).

SoCal Edison argues that local furnishing utilities should be required to comply with the Final Rule without any exception based upon their tax-exempt bonds.

Commission Conclusion

Private Activity Bonds

As we explained in Order No. 888, it is not our purpose to disturb Congress's and the IRS's determinations with respect to tax-exempt financing. With respect to private activity bonds, we reaffirm our finding that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities. We remain hopeful that the IRS in its private activity bond rulemaking will, to the maximum extent possible, remove regulatory impediments that limit the ability of industry participants to provide reciprocal open access. As we indicated in Order No. 888, after the IRS acts, we will reexamine our policy to ensure that the reciprocity condition is applied broadly to achieve open access without jeopardizing tax-exempt financing.[FN361]

We will reject the request of EEI and Tucson Power that the Commission require non-public utilities to substantiate in a safe harbor proceeding a claim that their tax status is a bar to granting reciprocity. As we stated in Order No. 888, if a non-public utility has sought a declaratory order on a voluntarily-filed tariff, we request that it identify the services, if any, that it cannot provide without jeopardizing the tax-exempt status of its financing. However, we cannot require that a non-public utility use the safe harbor mechanism, whether to file a reciprocal tariff with the Commission or to substantiate a claim as to loss of tax-exempt status. As we explain above, the safe harbor procedure is a voluntary means for non-public utilities to obtain a Commission determination that they meet the reciprocity condition in the open access tariffs and thereby avoid potential delays or denials of open access service based on allegations that the transmission requestor does not meet reciprocity.

Nevertheless, just as we believe that it is appropriate to condition the use of public utility open access tariffs on the ***12344** agreement of the tariff user to provide reciprocal access to the transmission provider, we also believe it is appropriate to condition the use of public utility open access tariffs on the agreement of the non-public utility tariff user to substantiate any claim that providing reciprocal transmission service would jeopardize the tax-exempt status of its financing. The non-public utility can provide such substantiation by identifying for the customer the services that it cannot provide without jeopardizing its tax-exempt financing.[FN362]

Southern suggests that tax-exempt status can remain undisturbed if non-public utilities do not seek open access transmission service from public utilities and, therefore, that non-public utilities can weigh the benefits of transmission service under the Rule against the potential threat to their tax benefits. We believe it is important to remember why we required open access in the first place—as a remedy for undue discrimination in transmission services in interstate commerce. Southern would force a non-public utility to give up a Congressionally-mandated right as a condition to taking open access transmission. Clearly Southern's suggestion is misplaced and overbroad.[FN363] For this reason, we believe that our decision not to require reciprocal service if providing such service would jeopardize the non-public utility's tax-exempt financing—pending action by the IRS in its private activity bond rulemaking—is appropriate for the time being.[FN364] We reiterate that we will reexamine our policy after the IRS acts. As we state above, we believe that ultimately the public interest is best served by nationwide open access.

Local Furnishing Bonds

We clarify, in response to Local Furnishing Utilities and ConEd, that the reference to "Transmission Service" in section 5.1 of the pro forma tariff was intended to be to "transmission service," and thereby to apply to point-to-point service as well as network service. We have revised section 5.1 accordingly.

We further clarify that all costs associated with the loss of tax-exempt status, including the costs of defeasing, redeeming, and refinancing tax-exempt bonds, are properly considered costs of providing transmission services. Therefore, a customer that takes service, understanding that such service will result in loss of tax-exempt status, shall be responsible for such costs to the extent consistent with Commission policy, and a transmission provider may include in its tariff a provision permitting it to seek recovery of such costs. We clarify that if the transmission customer is not willing to pay the costs associated with the transmission provider's loss of tax-exempt status, the transmission provider will not be required to provide the requested service.[FN365]

Local Furnishing Utilities and ConEd also ask the Commission to revise section 5.2 of the pro forma tariff to state that issuance of a section 211 order by the Commission is a condition precedent to the provision of transmission service. Under the tariff provision adopted by Order No. 888 to address situations in which the provision of transmission service would jeopardize the tax-exempt status of any local furnishing bonds used to finance a local furnishing utility's facilities, the customer requesting transmission service would tender an application under section 211 of the FPA. Within ten days of receiving a copy of the section 211 application, the transmission provider "will waive its rights to a request for service under Section 213(a) of the [FPA] and to the issuance of a proposed order under Section 212(c) of the [FPA] and shall provide the requested transmission service in accordance with the terms and conditions of this Tariff."[FN366] We clarify that the Commission, upon receipt of the transmission provider's waiver of its rights to a request for service under section 213(a) and to the issuance of a proposed order under section 212(c), shall issue an order under section 211.[FN367] Upon issuance of the order under section 211, the transmission provider shall be required to provide the requested transmission service in accordance with the terms and conditions of the tariff. Section 5.2 of the pro forma tariff has been revised accordingly.

Local Furnishing Utilities and ConEd also contend that the language of sections 5.1 and 5.2(i) of the pro forma tariff improperly limits the safe harbor protection of section 1919 of EPAct to transmission providers that financed transmission facilities with local furnishing bonds. ConEd expresses concern that although all of its electric local furnishing bonds have been used to finance its distribution system, the test as to whether those bonds have been used for the "local furnishing" of electricity is based in part on whether ConEd has been a "net importer" of energy into its service territory. As a result, ConEd argues that the use of its transmission system to wheel power from a generating source located inside ConEd's service territory to a customer located outside its service territory could cause ConEd to violate the net importer rule and thereby lose the tax exemption for the bonds used to finance its distribution system. ConEd asks the Commission to modify sections 5.1 and 5.2 of the pro forma tariff to make clear that those provisions apply to transmission providers that have financed any "facilities" (i.e., distribution and generation, not just transmission, facilities) with local furnishing bonds.

As we explained in Order No. 888, we believe the local furnishing bonds ***12345** provision in section 5 of the pro forma tariff is necessary and appropriate so that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime. If the provision of transmission service pursuant to Order No. 888 would result in the loss of tax-exempt status for local furnishing bonds, regardless of whether the facilities financed with those bonds are transmission, distribution, or generation facilities, it is our intent that the provisions of section 5 would apply. Thus, we clarify in response to ConEd and Local Furnishing Utilities that, to the extent the provision of transmission under an open access tariff would jeopardize the tax-exempt status of local furnishing bonds used to finance distribution or generation facilities (even if no transmission facilities were financed with such bonds),[FN368] such situation would fall within the reference to "facilities that would be used in providing . . . transmission service" contained in sections 5.1 and 5.2(i). This is so because the loss of tax-exempt status in such circumstances would be directly attributable to the provision of transmission services under the Rule.

Further, we said in Order No. 888 that "we will require any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff" a provision similar to section 5 of the pro forma tariff.[FN369] We clarify that we did not intend by this statement that the section 5 local furnishing bonds provision would only apply to public utilities that have financed transmission facilities with local furnishing bonds, and not those that have financed generation and distribution facilities with such bonds. As we explain above, it is our intent that the provisions of section 5 apply if the provision of transmission service pursuant to an open access tariff would result in the loss of tax-exempt status for local furnishing bonds, regardless of whether the facilities financed with those bonds are transmission, distribution, or generation facilities.

Rehearing Requests

Unfunded Mandates Reform Act

NE Public Power District[FN370] argues that the final regulations adopted in this proceeding "constitute[] an unfunded mandate under the Unfunded Mandates Reform Act of 1995 * * * ." [FN371] It declares that Order No. 888 imposes significant costs upon local governments and that the Commission was required under the Unfunded Mandates Reform Act to consider the financial impact of its rulemaking upon state and local governments and to prepare and issue as part of its rulemaking process a statement containing certain specified analyses and estimates concerning this matter and a description of its pre-issuance consultations with state and local government authorities. To support its argument NE Public Power District relies upon: (a) Executive Order No. 12875, Enhancing the Intergovernmental Partnership (Executive Order);[FN372] and (b) the Unfunded Mandates Reform Act of 1995 (the Act).[FN373]

Commission Conclusion

We disagree with NE Public Power District. The Executive Order applies to every "executive department * * * [and] agency. * * * "[FN374] It defines "executive agency" as "any authority of the United States that is an 'agency' under 44 U.S.C. §3502(1), other than those considered to be independent regulatory agencies, as defined in 44 U.S.C. §3502 (10)."[FN375] In section 3502(10), the Federal Energy Regulatory Commission is defined as an independent regulatory agency. As a result, the Executive Order does not apply to the Commission.

The Act similarly applies to federal agencies, but, as with the Executive Order, does not apply to independent regulatory agencies.[FN376] Although the Act does not define "independent regulatory agency," there is no indication that Congress intended to exclude the Commission from the definition. In fact, in all instances in which Congress has defined the term "independent regulatory agency" of which we are aware, the Commission has been included.

As noted, the Commission is defined as an independent regulatory agency in Title 44 U.S.C. Also, Title 42 U.S.C. §7176 provides that:

For the purposes of chapter 9 of title 5, United States Code * * * [Executive Reorganization], the [Federal Energy Regulatory] Commission shall be deemed to be an independent regulatory agency.[FN[377]]

Accordingly, we find that the Commission is an independent regulatory agency as used in the Act; therefore, it is not covered by the Act.

Moreover, even if the Act applied to the Commission, the Final Rule will not impose a Federal mandate on state, local or tribal governments.

Section 305 of the Act defines a "Federal mandate" as:

any provision in [a] statute or regulation or [in] any Federal court ruling that imposes an enforceable duty upon State, local, or tribal governments [,] including a condition of Federal assistance or a duty arising from participation in a voluntary Federal program.[FN[378]]

The Open Access Final Rule imposes requirements only on certain public utilities[FN379] and, pursuant to section 201(f) of the FPA, state and local ***12346** governments, and their agencies, authorities and instrumentalities, are not public utilities. Additionally, although the Final Rule will allow public utilities' transmission tariffs to contain reciprocity provisions in order to ensure that public utilities offering open access transmission to others can obtain similar service from open access users, the reciprocity provision is not an enforceable duty. A duty is mandatory; it is an obligation to perform and is compulsory. [FN380] The reciprocity provision is merely a condition of receiving a benefit, i.e., open access transmission service from a public utility.[FN381] There is no requirement that NE Public Power District promulgate an open access tariff and apply to FERC for a declaratory order. Moreover, as we explained above, non-public utilities, such as NE Public Power District, are free to seek from a public utility a waiver of the open access tariff reciprocity condition.

With regard to the Stranded Cost Final Rule, while it applies to non-public utilities as well as public utilities, it does not impose a duty on any entity since it merely permits public utilities and transmitting utilities to seek recovery of certain costs. As a result, since the Open Access and Stranded Cost final rules will not impose an enforceable duty on state, municipal or tribal power agencies such as NE Public Power District, the rules are not Federal mandates as defined in the Act.

Because the Unfunded Mandates Reform Act of 1995 does not apply to the Commission and, in any event, the Open Access/ Stranded Cost final rules do not impose Federal mandates on state, local or tribal governments, we reject NE Public Power District's argument that the Unfunded Mandates Reform Act of 1995 is applicable here.

5. Liability and Indemnification

In the Final Rule, the Commission explained that the indemnification provision was broken into two parts (set forth in section 10.1 (Force Majeure) and section 10.2 (Indemnification) of the pro forma tariff).[FN382] The Commission explained that the first part is a force majeure provision which provides that neither the transmission provider nor the customer will be in default if a force majeure event occurs, but also provides that both the transmission provider and customer will take all reasonable steps to comply with the tariff despite the occurrence of a force majeure event.

The Commission explained that the second portion of the provision provides for indemnification against third party claims arising from the performance of obligations under the tariff. The Commission limited the indemnification portion of the provision so that it is only the transmission customer who indemnifies the transmission provider from the claims of third parties. The Commission explained that the revised provision provides that the customer will not be required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission provider.

Rehearing Requests

A number of utilities argue that the Commission has expanded transmitter liability beyond the existing standard in the industry, i.e., gross negligence.[FN383] They assert that the Commission has provided no basis to subject transmission providers to liability, including consequential damages, due to ordinary negligence. KCPL points out that 21 of 25 states addressing this issue hold that a utility should not be liable for ordinary negligence. It declares that society will be worse off in litigation expenses and wasted human resources if utilities are held liable for simple negligence. It adds that the electric industry is much more susceptible to liability from interruptions of service than gas pipelines (refuting the Commission's reliance on Pacific Interstate Offshore Company, which it states is traceable to United Gas Pipeline Co. v. FERC, 824 F.2d 417 (5th Cir. 1987)). Florida Power Corp asks the Commission to modify section 10.2 to provide that a customer must indemnify the transmission provider except where a finder of fact determines that the transmission provider has committed gross or intentional wrongdoing. It also argues that the Commission should eliminate liability of both the transmission provider and the customer to the other for consequential damages.

Southern argues that the exception language in section 10.2 should be changed to "except where a court has determined that the Transmission Provider has engaged in intentional wrongdoing or has been grossly negligent." (Southern at 20-21). Southern also argues that the Commission should limit consequential damages arising from negligence in the operation of the transmission system.

Puget asserts that the exception language in section 10.2 should be changed to "except in cases of and to the extent of comparative or contributory negligence or intentional wrongdoing by the Transmission Provider." (Puget at 18). It also asserts that the Commission should exclude liability for special, incidental, consequential, or indirect damages.

EEI argues that the Commission should add a new section 10.3: "If the Transmission Provider is found liable for any damages associated with this Tariff, those damages shall be limited to direct damages, and the Transmission Provider shall not be liable for any special, indirect or consequential damages of any nature by virtue of the transactions conducted under this Tariff." (EEI at 26).

Coalition for Economic Competition argues that the Commission should modify section 10.2 to provide that the transmission provider will not be liable to a transmission customer or any third party for damages caused by interruptions or irregular or defective service, except if gross negligence or wilful misconduct caused such damages.[FN384] Coalition for Economic Competition asserts that the definition of force majeure should include ordinary negligence and asks that the Commission clarify that a utility is not liable for force majeure events.

CCEM also argues that transmission customer indemnity in section 10.2 should attach only to legal actions brought by customers of the transmission customer or third-party beneficiaries of those customers.

On the other hand, TDU Systems argues that the indemnity provision unfairly provides the transmission provider with virtually total indemnification for acts on its side of the delivery point, but provides no reciprocal protection to the transmission customers for damage incurred on the customers' system in connection with purchasing the transmission provider's services. ***12347**

CSW Operating Companies asks the Commission to revise the pro forma tariff to provide that a transmission provider will not be liable for errors in an estimate made in good faith and in accordance with its published procedure. They propose the following language:

Information posted on the OASIS concerning the availability of transfer capability will be based on the Transmission Provider's best estimates given the information readily and actually available to the transmission provider. No such estimate will be binding on the Transmission Provider for any purpose.

Alternatively, they ask the Commission to clarify that as long as a transmission provider in good faith follows its published methodology for determining ATC and TTC it will be deemed not to be negligent.

Commission Conclusion

The purpose of the force majeure provision in the pro forma tariff is to ensure that neither the customer nor the transmission provider is held in default in the event of an unpredictable and uncontrollable force majeure event. It was not the Commission's intention that the force majeure clause provide an avenue for a party to claim that it is excused from liability for its own negligence. A force majeure event does not include an act of negligence or intentional wrongdoing. The pro forma tariff will be changed accordingly.[FN385]

The purpose of the indemnification provision is to allocate the risks of a transaction, and the costs associated with those risks, to the party on whose behalf the transaction has been conducted, the transmission customer. As the tariff does not obligate the customer to perform services on behalf of the transmission provider, there is no comparable basis for imposing an indemnification obligation on the transmission provider.[FN386]

As is explained in the Final Rule, the Commission does not believe it appropriate to extend the indemnification obligation so that it would apply even in cases where the transmission provider has been negligent. The contention that electric transmission outages are either more frequent or more costly than gas outages does not serve to distinguish the electric transmission situation from the gas pipeline cases in which the Commission has found that indemnification clauses should not protect the pipeline owner from its own negligence.[FN387] In either case, it would be inappropriate to require the customer to indemnify the transmission provider from damages arising from the transmission provider's own negligence. We note, however, that liability is a separate issue from indemnification. Despite the absence of indemnification protection, there is nothing in the indemnification provision that would preclude transmission providers from relying on the protection of state laws, when and where applicable, protecting utilities or others from claims founded in ordinary negligence.

With respect to the issue of consequential and indirect damages, the indemnification provision already provides protection to the transmission provider from consequential and indirect damage claims by third parties except in cases of negligence or intentional wrongdoing by the transmission provider. The Commission sees no need to further extend this protection. Again, we note that liability is a separate issue from indemnification, and that nothing in these provisions precludes transmission providers or customers from relying, when and where such law is applicable, on the protection of statutes or other law protecting parties from consequential or indirect damages.

Furthermore, we will not revise the pro forma tariff, as requested by CSW Operating Companies, to provide that a transmission provider will not be liable for errors in an estimate made in good faith or in accordance with its published procedure. We believe that a utility should have no different a liability standard for operating an OASIS than for its other operations.[FN388]

6. Umbrella Service Agreements

The Commission received requests for clarification regarding this issue, which was not specifically addressed by the Commission in the Final Rule.

Rehearing Requests

SoCal Edison argues that it is too burdensome to require a separate Completed Application and a separate Service Agreement to be executed for each individual service transaction for short-term firm and non-firm transmission service (and filed with the Commission). SoCal Edison contends that requiring a separate service agreement for each short-term firm transaction to be filed with the Commission will stifle transactions in the short-term market. It indicates that it suggested a simpler approach in Docket No. ER96-222-000 that would establish a non-transaction specific Service Agreement and a Completed Application that would contain the specific transaction information, but would not be filed with the Commission, but would be made available for audit.[FN389]

Commission Conclusion

SoCal Edison misinterprets the tariff provisions regarding service agreements for non-firm point-to-point transmission service. Tariff section 14.5 details the treatment of service agreements for non-firm transmission service:

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. (Emphasis added)

Moreover, in tariff section 18 (Procedures for Arranging for Non-Firm Point-To-Point Transmission Service) requires that a separate service agreement be executed for each individual service transaction as claimed by SoCal Edison. In the pro forma tariff, the Commission established a non-transaction specific (or "umbrella") service agreement in an attempt to streamline the application procedures for non-firm point-to-point transmission service. Therefore, the service agreement for non-firm point-to-point transmission service need only be executed and filed with the Commission once, when the transmission customer first applies for non-firm point-to-point transmission service. Subsequent non-firm transactions by the same customer only require the submission of a completed application (as provided in tariff sections 18.1 and 18.2) by that customer, which will be submitted via the transmission provider's OASIS (when the OASIS is fully implemented). Accordingly, no changes are required to ***12348** the application procedures for non-firm point-to-point service.

However, we do find SoCal Edison's arguments persuasive that streamlined procedures should also be applied to applications for firm point-to-point transmission service with a duration of less than one year (short-term firm). We agree that there is no compelling reason to require the submission of separate service agreements for every short-term firm transaction. Accordingly, we will adopt an "umbrella" service agreement approach (as is currently used for non-firm point-to-point transactions) and require a service agreement of general applicability to be filed with the Commission when the first short-term firm transaction is arranged between the transmission provider and customer.