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Preventing Undue Discrimination and Preference in Transmission Service; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 37

[Docket Nos. RM05–17–001, 002 and RM05–25–001, 002; Order No. 890–A]

Preventing Undue Discrimination and Preference in Transmission Service

Issued December 28, 2007.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order on rehearing and clarification.

SUMMARY: The Federal Energy Regulatory Commission affirms its basic determinations in Order No. 890, granting rehearing and clarification regarding certain revisions to its regulations and the *pro forma* open-access transmission tariff, or OATT, adopted in Order Nos. 888 and 889 to ensure that transmission services are provided on a basis that is just, reasonable, and not unduly discriminatory. The reforms affirmed in this order are designed to: (1) Strengthen the *pro forma* OATT to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and (3) increase transparency in the rules applicable to planning and use of the transmission system.

DATES: *Effective Date:* This rule will become effective March 17, 2008.

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

I. Introduction

1. On February 16, 2007, the Commission issued Order No. 890,[1] addressing and remedying opportunities for undue discrimination under the *pro forma* Open Access Transmission Tariff (OATT) adopted in Order No. 888.[2] The *pro forma* OATT was intended to foster greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. In the ten years since Order No. 888, however, flaws in the *pro forma* OATT undermined its ability to realize the core objective of remedying undue discrimination. The Commission acted in Order No. 890 to correct these flaws by reforming the terms and conditions of the *pro forma* OATT in several critical areas, including the calculation of available transfer capability (ATC), the planning of transmission facilities, and the conditions of services offered by each transmission provider.

2. Many have expressed support of the Commission's reforms. Greater specificity regarding the transmission provider's obligations under its OATT will reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement of the tariff. Greater transparency in the rules applicable to the planning and use of the transmission system will help both transmission providers and customers comply with applicable tariff requirements. Although we grant rehearing and clarification below to address certain implementation issues raised by petitioners, we leave in place the fundamental reforms adopted in Order No. 890.

3. At the outset, we note that work is well underway to develop consistent practices governing the calculation of ATC, in coordination with the North American Electric Reliability Corporation (NERC) and the North American Energy Standards Board (NAESB). Eliminating the broad discretion that transmission providers currently have in calculating ATC will increase nondiscriminatory access to the grid and ensure that customers are treated fairly in seeking alternative power supplies. We commend transmission providers for the substantial resources they have dedicated to this process and NERC and NAESB for their leadership in guiding the standardization effort.

4. We also commend transmission providers for the substantial resources dedicated to the development of transmission planning processes in response to Order No. 890. Transmission providers and stakeholders recently submitted tariff proposals that will govern transmission planning under the *pro forma* OATT. Transmission planning is critical because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives. It is therefore vital for each transmission provider to open its transmission planning process to customers, coordinate with customers regarding future system plans, and share necessary planning information with customers.

[1] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 FR 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) (Order No. 890).

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

5. In addition, transmission providers have implemented new service options for long-term firm point-to-point customers and adopted modifications to other services. Instead of denying a long-term request for point-to-point service because as little as one hour of service is unavailable, transmission providers must now consider their ability to offer a modified form of planning redispatch or a new conditional firm option to accommodate the request. This increases opportunities to efficiently utilize transmission by eliminating artificial barriers to use of the grid. Charges for energy and generation imbalances also have been standardized, including relaxed penalties for intermittent resources. This standardization reduces the potential for undue discrimination, increases transparency, and reduces confusion in the industry that resulted from the prior lack of consistency.

6. Taken together, these and other reforms adopted in Order No. 890 will better enable the *pro forma* OATT to achieve the core object of remedying undue discrimination in the provision of transmission service. The Commission therefore rejects requests to eliminate, or substantially modify, the various reforms adopted in Order No. 890.[3] We address each of the arguments made by petitioners in turn. We also address comments received in response to the technical conference held by Commission staff on July 30, 2007, regarding certain issues related to the designation and termination of network resources, in section III.D.5.[4]

II. Need for and Applicability of Order No. 888

A. The Need for Reform

7. As the Commission noted in Order No. 888, it is in the economic self-interest of transmission monopolists to deny transmission to competitors or to offer transmission on a basis that is inferior to that which they provide themselves.[5] The Commission sought to remedy that potential for discrimination through adoption of the pro forma OATT in Order No. 888. Despite the many accomplishments of Order No. 888, the Commission determined in Order No. 890 that the existing *pro forma* OATT continued to allow transmission providers substantial discretion in implementing some of its basic requirements. This discretion, in turn, created substantial opportunities for undue discrimination. Order No. 890 reformed the *pro forma* OATT to limit opportunities for undue discrimination and promote efficient use of the grid.

8. In Order No. 890, the Commission rejected arguments that it was relying on unsubstantiated allegations of discriminatory conduct to justify its reforms. Although certain commenters did allege discriminatory conduct in response to the Notice of Proposed Rulemaking (NOPR) initiating this proceeding,[6] the Commission made clear that it was not making specific factual findings of discrimination and that such specific findings were not required in order for it to promulgate a generic rule to eliminate undue discrimination.[7] The Commission explained that it had ample grounds to act as necessary to limit opportunities for undue discrimination that continue to exist under the pro forma OATT.

Requests for Rehearing and Clarification

9. Many petitioners agree with the Commission on rehearing that reforms to the *pro forma* OATT are needed because there continues to be both the opportunity and incentive for transmission providers to engage in undue discrimination.[8] Two petitioners, however, seek rehearing of that finding as sufficient justification for adopting the reforms set forth in Order No. 890.

10. E.ON U.S. argues that the Commission has not presented any actual evidence of discrimination or opportunities for undue discrimination. Without actual evidence of discrimination, E.ON U.S. argues that the Commission lacks reasoned support for its finding that the reforms adopted in Order No. 890 are necessary to remedy undue discrimination. E.ON U.S. states a particular concern for the cost of implementing these reforms. E.ON U.S. contends that, absent evidence of unduly discriminatory behavior, the burdensome nature of compliance with Order No. 890 outweighs the benefits of its reforms.

11. Southern expresses similar concern that Order No. 890 lacks actual findings of discrimination. Southern claims that the theoretical claims of discrimination relied upon by the Commission are attenuated and inconsistent with statements discouraging commenters from making sweeping generalizations regarding undue discrimination. Rather than predicating Order No. 890 on the Commission's authority to prevent undue discrimination, Southern suggests that the Commission clarify that it is promulgating these reforms pursuant to its authority to ensure just and reasonable rates and not to prevent undue discrimination.

12. Southern also argues that the Commission failed to acknowledge other legal requirements and processes adopted after issuance of Order No. 888 that mitigate a transmission provider's incentives to discriminate, such as the Standards of Conduct, enforcement audits, new civil penalty authority, and mandatory reliability standards. Southern contends that transmission providers have a pecuniary incentive to grant, rather than deny, customer requests since doing so provides additional OATT revenues. Southern argues that the Commission appears to equate discretion with opportunities for discrimination, yet in certain circumstances expressly acknowledges that the transmission provider retains discretion in certain activities.

Commission Determination

13. The Commission concluded in Order No. 890 that reforms to the *pro forma* OATT were necessary to address remaining opportunities for undue discrimination by transmission providers. Despite the efforts of Order No. 888 and our subsequent reforms, including those cited by Southern, opportunities for undue discrimination continued to exist. Under section 206 of the FPA, the Commission has a continuing obligation to ''determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices

[3] A list of petitioners filing requests for rehearing and/or clarification is provided in Appendix A. The requests for rehearing filed by American Transmission, Bonneville, EPSA, Pacific Northwest Parties, and REPIO are deficient because they fail to include a Statement of Issues section separate from the arguments made, as required by Rule 713 of the Commission's Rules of Practice and Procedure. *See* 18 CFR 385.713(c)(2). Consistent with Rule 713, we deem these petitioners to have waived the particular issues for which they seek rehearing. We also reject TranServ's request for rehearing for having been filed late, in violation of section 313(a) of the Federal Power Act (FPA). *See* 16 U.S.C. 8351(a). The Commission does consider, however, these petitioners' requests for clarification, to the extent they are not in fact requests for rehearing. We also address the merits of each request for rehearing to demonstrate that, had they been considered, our decision would be unchanged.

[4] A list of parties filing comments in response to the July 30, 2007 technical conference is provided in Appendix B.

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

[6] *Preventing Undue Discrimination and Preference in Transmission Service,* Notice of Proposed Rulemaking, 71 FR 32,636 (Jun. 6, 2006), FERC Stats. & Regs. ¶ 32,603 (2006) (NOPR).

[7] *See* Order No. 890 at P 41 (citing *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom., New York* v. *FERC,* 535 U.S. 1 (2002); *National Fuel Gas Supply Corp* v. *FERC,* 468 F.3d 831 (D.C. Cir. 2006)).

[8] *See e.g.,* Constellation, MISO, NRECA, Powerex, PSEG, and TAPS.

that do no meet this standard.'' [9] The Commission's finding that continuing opportunities to discriminate exist therefore supports our action under FPA section 206 to adopt changes to the *pro forma* OATT. Upon review of the extensive record of this proceeding, including the support of a vast majority of commenters, the Commission remains convinced that the particular reforms adopted in Order No. 890 are appropriate to satisfy our obligation to remedy undue discrimination.

14. We reject E.ON U.S.' arguments that, without actual evidence of undue discrimination, Order No. 890 lacks reasoned support. As the Commission explained in Order No. 890, the courts have made clear that the Commission need not make specific factual findings of discrimination in order to promulgate a generic rule to eliminate undue discrimination. In *Associated Gas Distributors* v. *FERC*, the D.C. Circuit Court explained that the promulgation of generic rate criteria involves the determination of policy goals and the selection of the means to achieve them.[10] The court concluded that, just as courts do not insist on empirical data for every proposition upon which the selection depends, ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [11] The Commission exercised this authority in Order No. 890, discussing with particularity the concerns motivating each of the reforms adopted. As it did in Order No. 888, the Commission properly acted to limit continuing opportunities for undue discrimination, not to remedy actual instances of undue discrimination.

15. We acknowledge, as argued by Southern, that it is appropriate for transmission providers to retain discretion in some areas and that such discretion does not necessarily equate to discrimination. It is also true that some OATT revenues may increase as requests for service are granted (such as for point-to-point requests), rather than denied. This is not always or even predominantly the case, however, given that rates for network service are based on load-ratio shares and revenues do not increase with designations of network resources unless new facilities are constructed. Moreover, there are competing incentives for a transmission provider to deny or restrict service to customers in certain circumstances and allowing broad discretion in such areas is no longer appropriate. The Commission identified these areas in Order No. 890, including the calculation of ATC, planning for transmission needs, and the provision of certain transmission services, and acted to remedy potential discrimination in each area. Notwithstanding the other legal requirements and processes cited by Southern, the Commission concluded in Order No. 890 that the reforms adopted were necessary based on a decade of experience administering the *pro forma* OATT. While the Standards of Conduct, audit procedures, and enhanced authority under the Energy Policy Act of 2005 (EPAct 2005) [12] have aided the Commission in fulfilling its obligations under the FPA, the reforms adopted in Order No. 890 are also necessary to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement of the open access requirements.

16. We appreciate that a significant amount of resources must be dedicated to implementation of the reforms adopted in Order No. 890 by transmission providers. We believe the burden of implementing these reforms is fully justified by the need to eliminate remaining opportunities for undue discrimination in the administration and implementation of open access requirements under the *pro forma* OATT. We note, moreover, that these reforms will benefit transmission providers seeking to comply with our regulations in good faith by providing more clarity regarding the requirements of the *pro forma* OATT previously left open to interpretation, thereby decreasing the possibility of disputes with transmission customers and enforcement actions by the Commission. The ability of transmission customers to misuse the tariffs to their own advantage, particularly in the scheduling process, has similarly been addressed. Taken together, we conclude that the benefits of our reforms outweigh the associated costs of implementation.

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

17. Although Order No. 890 introduced many important reforms, the Commission also retained many core elements from Order No. 888. As noted in the NOPR, many provisions of Order No. 888 enjoy broad support from many sectors of the industry and the Commission did not intend in this proceeding to pursue the same level of industry restructuring undertaken there. Rather, the Commission intended Order No. 890 to strengthen the *pro forma* OATT while retaining the fundamental structure articulated in Order No. 888.

18. The Commission thus retained the existing boundaries between wholesale and retail service drawn in Order No. 888. The Commission also retained the native load priority established in Order No. 888. The Commission stated that this priority continues to strike the appropriate balance between the transmission provider's need to meet its native load obligations and the needs of other entities to obtain service from the transmission provider to meet their own obligations. Order No. 890 also did not alter the types of services required under Order No. 888, *i.e.*, network service and point-to-point service. Finally, the Commission retained the functional unbundling requirement promulgated in Order No. 888.

Requests for Rehearing and Clarification

19. South Carolina E&G objects to the Commission's decision to retain the native load priority established in Order No. 888, arguing that FPA section 217 requires further protection for native load service. South Carolina E&G states that the native load priority adopted under Order No. 888 was implemented so that all customers, native load and non-native load, would be entitled to equivalent, nondiscriminatory service.[13] South Carolina E&G argues that FPA section 217(k) now entitles load-serving entities (LSEs) to use their transmission systems to meet their state-law imposed native load service obligations and that this entitlement can no longer be deemed discriminatory under the FPA. To the extent an OATT provision compromising native load service is grounded in a finding of undue discrimination, South Carolina E&G argues that it must yield to the need to meet native load service obligations.

20. Joined by South Carolina Regulatory Staff, South Carolina E&G objects in particular to the Commission's decision to retain equal curtailment priority for all firm service.[14] These petitioners argue that requiring transmission providers to curtail service to network and point-to-point customers on a basis comparable to the curtailment of service to native load customers unfairly exalts non-native customers at the expense of the

[9] Order No. 888 at 31,669.

[10] 824 F.2d 981 (D.C. Cir. 1987).

[11] *Id.* at 1008.

[12] Pub. L. No. 109–58, 119 Stat. 594 (to be codified in scattered titles of the U.S.C.).

[13] *Citing Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282 at P 125 (2006).

[14] South Carolina E&G and South Carolina Regulatory Staff also argue that reforms related to planning redispatch and conditional firm, rollover rights, and capacity reassignment are in violation of FPA section 217. We address those arguments in sections III.D.1, III.D.2, and III.C.3 respectively.

native load that financed the transmission system. They also contend the Commission's decision is inconsistent with *Northern States Power Co.* v. *FERC*,[15] which they argue prohibits mandating comparable curtailment priority among native load and non-native load services in the face of a state commission edict requiring a transmission provider to give its native load top curtailment priority. In their view, this precedent must be read broadly in light of enactment of FPA section 217(k), which they contend peremptorily counters any argument that priority for native load would be discriminatory.

21. E.ON LSE similarly argues that FPA section 217 categorically protects an LSE's use of firm transmission service to the extent that such transmission service is required to meet the LSE's service obligation. E.ON LSE asks the Commission to allow LSEs to deviate from the requirements of Order No. 890 in circumstances where, in the LSE's good faith judgment, compliance would adversely affect the provision of firm transmission service to native load protected by FPA section 217.

22. TDU Systems request clarification or rehearing to confirm that there is no preference under the reformed *pro forma* OATT for a public utility transmission provider's native load over the service obligations of other LSEs that use their transmission system. TDU Systems argue that section 217(a) of the FPA does not distinguish between the service obligations of transmission providers and the service obligations of their load serving customers and, therefore, neither should the *pro forma* OATT.

Commission Determination

23. The Commission affirms the decision to retain the native load protections embodied in Order No. 888, as enhanced by the reforms adopted in Order No. 890. In Order No. 888, the Commission gave public utilities the right to reserve existing transmission capacity needed for native load growth reasonably forecasted within the utility's current planning horizon.[16] The Commission also allowed transmission providers to restrict rollover rights based on reasonably forecasted need at the time the contract is executed.[17] Contrary to petitioner's assertions, the native load protections affirmed in Order No. 890 satisfy the requirements of FPA section 217. Section 217 applies not only to distribution utilities providing service to end-users, but also to electric utilities with long-term contracts to provide service to a distribution utility.[18] Congress placed each of these types of customers on equal footing, regardless of their status as a network or firm point-to-point customer under the *pro forma* OATT or a transmission provider serving its native load. We therefore disagree with petitioners that section 217 requires the Commission to give top curtailment priority solely to network customers or the transmission provider serving native load.

24. We decline to allow LSEs to deviate from the requirements of the *pro forma* OATT as they believe necessary to serve their native load, as suggested by E.ON LSE. Section 217 is intended to facilitate the ability of all utilities using firm transmission to meet their long-term service obligations, which the statute defines broadly to include not only service to end-users, but also distribution utilities serving end-users.[19] The requirements of the *pro forma* OATT and the reforms adopted in Order No. 890 appropriately balance the needs of these various classes of transmission customers, including the transmission provider's native load, LSE customers serving network load, and other firm users of the system. This is entirely consistent with, if not expressly required by, FPA section 217.

C. Scope and Applicability of Order No. 890

25. The reforms adopted in Order No. 890 apply to all transmission providers, including Commission-approved regional transmission organizations (RTOs) and independent system operators (ISOs), and non-public utility transmission providers with reciprocity obligations. The particular process for implementing certain of the reforms adopted in Order No. 890 varied depending on the type of transmission provider at issue.

26. For those transmission providers that have not been approved as ISOs or RTOs, and whose facilities are not under the control or within the footprint of an ISO or RTO, Order No. 890 established a two-tiered compliance process for adopting the non-rate terms and conditions of the revised *pro forma* OATT. These transmission providers were directed to submit FPA section 206 compliance filings that contain the revised non-rate terms and conditions of the revised *pro forma* OATT within 60 days after publication of the order in the **Federal Register**.[20] Any of these transmission providers that wished to retain a previously-approved variation from the Order No. 888 *pro forma* OATT that was substantively affected by a reform adopted in Order No. 890 were directed to submit, within 30 days after publication of Order No. 890 in the **Federal Register**, a request under FPA section 205 to retain those previously-approved variations, provided they continued to be consistent with or superior to the revised *pro forma* OATT adopted in Order No. 890.

27. ISO and RTO transmission providers were directed to submit FPA section 206 compliance filings, within 210 days after the publication of Order No. 890 in the **Federal Register**, that contain the non-rate terms and conditions set forth in Order No. 890 or that demonstrate that their existing tariff provisions are consistent with or superior to the revised provisions of the *pro forma* OATT. Transmission-owning members of ISOs and RTOs, and non-ISO/RTO transmission providers within the footprint of an ISO or RTO, were similarly directed to make any necessary tariff filings within 210 days of its publication in the **Federal Register**.

28. With regard to non-public utility transmission providers, the Commission retained the reciprocity language of the Order No. 888 *pro forma* OATT with a few modifications. First, the Commission updated the language to contain references to ISOs and RTOs, requiring transmission customers that are members of, or that take service from, an ISO/RTO to make comparable service available to other members of the ISO/RTO. As proposed in the NOPR, the Commission did not adopt a generic rule to implement FPA section 211A, which allows the Commission to require an unregulated transmitting utility to provide transmission services at rates that are comparable to those it charges itself and under non-rate terms and

[15] 176 F.3d 1090 (8th Cir. 1999).

[16] *See* Order No. 888 at 31,394.

[17] *See id.* at 31,745.

[18] *See* EPAct 2005 sec. 1233(a)(3) (to be codified at section 217(a)(3) of the FPA, 16 U.S.C. 824q(a)(3)). Petitioners' reliance on *Northern States Power Co.* v. *FERC*, 176 F.3d 1090 (8th Cir. 1999), is therefore misplaced. As the Commission has explained, the court upheld our authority to require *pro rata* curtailment of both network/native load and firm point-to-point service except in the limited circumstance when it would require the shedding of bundled retail load. Indeed, FPA section 217 could be read to grant electric utilities with long-term contracts to provide service to a distribution utility equal curtailment priority with other LSEs even in that limited situation, although we decline to address that argument here as it has not been raised on rehearing.

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

[20] The Commission subsequently extended by 60 days the date on which the reforms adopted in Order No. 890 would have otherwise been effective. *See Preventing Undue Discrimination and Preference in Transmission Service*, 119 FERC ¶ 61,037 (2007) (April 11 Order).

conditions that are comparable to those it applies to itself, and are not unduly discriminatory or preferential. The Commission instead explained that it would follow a case-by-case approach to implementing FPA section 211A.

Requests for Rehearing and Clarification

29. Few petitioners question the applicability of Order No. 890, although some are concerned with the timing of the compliance actions required by the Commission. Southern asks the Commission to grant rehearing and extend the initial compliance deadlines by 60 days and to remain open to further requests for extension if the deadlines set forth in Order No. 890 cannot be met. MidAmerican asks the Commission to extend the effective date for the revisions to the *pro forma* OATT to the first day of the month following the effective date of these reforms. MidAmerican contends that it will be burdensome for transmission providers and confusing to transmission customers to implement the reforms adopted in Order No. 890 in the middle of a billing cycle.

30. TDU Systems express concern with the burden of reviewing section 205 filings by transmission providers seeking a determination from the Commission that a previously-approved variation from Order No. 888 continues to be consistent with or superior to the revised *pro forma* OATT. TDU Systems contend that reviewing and evaluating these filings will be a large and time-consuming process. TDU Systems ask the Commission to allow transmission customers 45 days to perform their own evaluation and comment upon these filings, while retaining a 90-day deadline for the Commission to process the filings. Alternatively, TDU Systems request rehearing of the Commission's decision not to stagger the due dates for the various compliance filings required in Order No. 890.

31. Although they recognize that Order No. 890 preserves existing waivers of the obligations to file an OATT, Unitil and Alcoa seek explicit confirmation that their waivers of the obligation to maintain an Open Access Same-Time Information System (OASIS) site are still valid. Unitil notes that the Commission has found that it does not operate or control an interstate transmission grid.[21] In addition, Unitil states that it voluntarily offers relevant information to ISO–NE for posting on its OASIS Web site. Similarly, Alcoa notes that the Commission has granted waiver of OASIS requirements to its Long Sault division, which owns five transmission lines in northern New York connecting Alcoa to its electric energy suppliers.[22] Thus, Unitil and Alcoa seek confirmation that the Commission did not intend the OASIS requirements outlined in Order No. 890 to apply to their operations.

32. NRECA requests clarification, or in the alternative rehearing, that the Commission did not intend in Order No. 890 to extend reciprocity obligations beyond transmission owning members of an ISO or RTO. NRECA contends that the Commission's modification to the *pro forma* OATT creates ambiguity by imposing the reciprocity obligation for all "members" of an ISO or RTO. NRECA points out that some members of ISOs and RTOs do not own transmission, such as transmission dependent utilities, state regulatory authorities and eligible end-use customers. NRECA argues that expanding the reciprocity obligation to require non-public utility transmission providers to provide service to non-transmission owning members of an ISO or RTO would contradict Commission precedent[23] and be unsupported by the record in this proceeding.

33. WSPP requests that the Commission establish a date by which it must submit a compliance filing containing the non-rate terms and conditions of the revised *pro forma* OATT. WSPP states that it is neither a transmission provider nor an RTO/ISO and, instead, only has a limited open access transmission tariff on file with the Commission. WSPP states that this tariff only applies to its transmission-owning members that do not otherwise have an OATT.

Commission Determination

34. In the April 11 Order, the Commission granted requests by EEI and others to extend by 60 days the date by which transmissions providers outside of ISO/RTO regions would have to submit compliance filings containing the non-rate terms and conditions of the revised *pro forma* OATT.[24] Southern's request for rehearing on this point is therefore moot. Similarly, we reject as unnecessary TDU Systems' request to allow transmission customers additional time to evaluate and comment upon compliance filings. These filings have already been made, comments have been filed, and in many cases orders addressing the filings have been issued.

35. The Commission also determined in the April 11 Order that it would be reasonable for a transmission provider to request that the imbalance-related provisions in Schedule 4 and Schedule 9 of the *pro forma* OATT be made effective on the first day of the billing cycle following the effectiveness of the underlying imbalance-related reforms.[25] MidAmerican does not explain or otherwise justify the need to delay the effectiveness of any other reforms until the following billing cycle. We therefore reject as moot MidAmerican's request to extend the effective date of the imbalance-related reforms adopted in Order No. 890 until the following billing cycle and reject as unsupported its request to extend the effective date of all other reforms adopted in Order No. 890.

36. The Commission made clear in Order No. 890 that the reforms therein were not intended to disturb any existing waivers of the obligation to file an OATT or otherwise offer open access transmission service.[26] The criteria for waiver of Order No. 890, moreover, remains unchanged from that used to evaluate the requests for waiver under Order Nos. 888 and 889. Revocation of any waivers will continued to be considered on a case-by-case basis in response to concerns raised by interested parties. We clarify that this applies equally to existing waivers of Order No. 889 and requirements to maintain an OASIS site.

37. We grant rehearing, in response to NRECA, to revise section 6 of the *pro forma* OATT to require a customer that is a member of or that takes service from an RTO or ISO to provide comparable service, to the extent it owns transmission facilities, only to the transmission-owning members of the RTO or ISO. The Commission has expressed concern in the past that failure to grant reciprocity to transmission-owning members of an RTO or ISO would cause those members to lose the right to reciprocity solely as a result of participating in the RTO or ISO.[27] We did not intend to expand that obligation in Order No. 890 to other members of an RTO or ISO when revising the language of section 6 of the *pro forma* OATT to refer to RTOs and ISOs.

38. Below the Commission adopts various other revisions to the *pro forma* OATT in response to requests for rehearing and clarification. These revisions do not disturb the

[21] *Citing Northern States Power Co.*, 76 FERC ¶ 61,250 at 62,297 (2002).

[22] *Citing Alcoa Power Generating, Inc. (Long Sault Division)*, 116 FERC ¶ 61,257 (2006).

[23] *Citing American Transmission Co. LLC*, 95 FERC ¶ 61,387 (2001).

[24] April 11 Order at P 20.

[25] *Id.* at P 22.

[26] *See* Order No. 890 at P 135, n.105.

[27] *See American Transmission Company LLC*, 93 FERC ¶ 61,267 at 61,858–59 (2000), *reh'g denied*, 95 FERC ¶ 61,387 at 62,446 (2001).

fundamental nature of the reforms adopted in Order No. 890 and, thus, we do not anticipate any difficulty in their implementation or disruption in on-going compliance efforts. We direct transmission providers that have not been approved as RTOs or ISOs, and whose facilities are not in the footprint of an RTO or ISO, to submit an FPA section 206 filing that contains the revised non-rate terms and conditions of the *pro forma* OATT stated in Appendix C within 60 days of publication of this order in the **Federal Register**. We direct RTO and ISO transmission providers, transmission providers whose facilities are in the footprint of an RTO or ISO, and WSPP to submit an FPA section 206 filing that contains the revised non-rate terms and conditions of the *pro forma* OATT as stated within Appendix C within 90 days of publication of this order in the **Federal Register**.

III. Reforms of the OATT

A. Consistency and Transparency of ATC Calculations

39. In Order No. 890, the Commission concluded that the lack of consistency and transparency in the methodology for calculating ATC creates the potential for undue discrimination in the provision of open access transmission service. To remedy this lack of consistency and transparency, the Commission directed public utilities, working through the NERC reliability standards and NAESB business practices development processes, to produce workable solutions to implement the ATC-related reforms adopted by the Commission. A number of petitioners seek rehearing and/or clarification regarding the Commission's ATC-related rulings, which we address below.

1. Consistency

a. Necessary Degree of Consistency

40. The Commission required industry-wide consistency of all ATC components [28] and certain definitions, data inputs, data exchange, and modeling assumptions in order to reduce the potential for undue discrimination in the provision of transmission service. Although the Commission concluded that the number of industry-wide ATC calculation formulas should be few in number, it did not require that a single ATC calculation methodology be applied by all transmission providers. The Commission found that it is not the methodologies for calculating ATC that create the opportunity for undue discrimination, rather the variability in the calculation of the components of ATC and the lack of a detailed description of the ATC calculation methodology and underlying assumptions used by the transmission provider.

41. The Commission noted that NERC was then in the process of developing standards for three ATC calculation methodologies: contract or rated path ATC, network ATC, and network Available Flowgate Capacity (AFC). The Commission concluded that, if all of the ATC components and certain data inputs and assumptions are consistent, the use of the three ATC calculation methodologies included in reliability standards being developed would be acceptable. With regard to network AFC, the Commission specifically directed public utilities, working through NERC, to develop an AFC definition and requirements used to identify a particular set of transmission facilities as a flowgate. However, the Commission reminded transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate. The Commission therefore directed public utilities, working through NERC, to develop in the MOD–001 standard a rule to convert AFC into ATC values to be posted by transmission providers that currently use the flowgate methodology.

42. The Commission also required further clarification regarding the calculation algorithms for firm and non-firm ATC. The Commission directed public utilities, working through NERC, to modify related ATC standards by implementing the following principles: (1) For firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows.

Requests for Rehearing and Clarification

43. Southern requests that the Commission clarify that consistency in ATC methodologies and CBM and TRM calculations must not take precedence over reliability and that some transmission provider discretion is necessary. Southern states that, in several places, Order No. 890 discusses minimizing transmission provider discretion in order to achieve consistency.[29] Southern contends that totally eliminating this discretion would not allow transmission providers to address unique system conditions in ATC, CBM, and TRM calculations, which would impact system reliability. Southern claims that eliminating transmission provider discretion also would lead to more conservative modeling, which would likely result in understated amounts of ATC and an inefficient use of the system.[30] To the extent making the treatment of certain ATC parameters or CBM or TRM calculations consistent would affect reliability, Southern asks that transparency in the treatment of those parameters and calculations be required, but that strict consistency not be enforced.

44. MidAmerican requests clarification that AFC quantities do not need to be converted into control area-to-control area path ATC quantities and that the Commission is not eliminating the coordination of individual transmission provider service with seams agreements and/or regional tariff service on flowgates. MidAmerican asks the Commission to confirm that it is merely intending to require NERC to define a flowgate ATC quantity which is equal to or related to the flowgate AFC. MidAmerican contends that transmission customers, operators, and owners will not benefit from the conversion of flowgate AFCs into control area-to-control area path ATCs, the elimination of AFC as a useful transmission commodity, or the elimination of the coordination of individual provider and regional transmission service over flowgates. To the extent the Commission feels there is a comparability benefit for the conversion of AFC to ATC, MidAmerican requests clarification that providing transmission customers with a mechanism on OASIS to query/assess the effective ATC on a specific transmission path over a specific time is sufficient for compliance with the transmission provider's ATC posting obligation.

45. E.ON U.S. requests clarification of the requirement that AFC calculations be converted into ATC for purposes of posting. E.ON U.S. states that some

[28] The ATC components are total transfer capability (TTC), existing transmission commitments (ETC), capacity benefit margin (CBM), and transmission reserve margin (TRM).

[29] *Citing* Order No. 890 at P 207.

[30] Southern suggests that one example of when a transmission provider should have discretion is when modeling long-term firm transmission service reservation from a combustion turbine generating facility. Southern argues that, by its nature, such a generating facility normally will not often run in off-peak times. During those times, or when there is an impending outage of a generating facility, Southern argues that the transmission provider should have the discretion to reflect the operating characteristics of the generating facility by not including transmission service from the facility in its model.

RTOs, such as MISO and others, utilize AFC and do not calculate or post ATC for their systems. Due to interactions with these RTOs, E.ON U.S. now calculates AFC as well. E.ON requests that the Commission clarify that if RTOs and their member utilities are granted waivers of the requirement to calculate and post ATC, in favor of AFC, all transmission owning utilities in the region should be able to request a waiver on the same basis. E.ON claims that allowing all transmission-owning utilities within a region to calculate AFC (instead of ATC) will result in greater accuracy and consistency within the industry.

46. Although it does not challenge the Commission's decision not to require a single, industry-wide ATC calculation method, TDU Systems claims that the Commission fails to address the situation where transmission providers on a single interface choose different ATC calculation methods. TDU Systems argue that transmission providers must be required to provide consistent ATC values on either side of an interface. TDU Systems therefore request that adjacent transmission providers be required to coordinate to provide consistent ATC values across their common interfaces.

47. NorthWestern requests that the Commission clarify that the consistency requirements of Order No. 890 do not prohibit utilities from reducing transfer capability for the purchase of reliability services. According to NorthWestern, some transmission providers may have to acquire various generation-based services, such as load following and regulation service, in the marketplace in order to meet reliability criteria. NorthWestern argues that some means should be allowed for retaining transmission at no cost for such deliveries, even though they do not meet the strict definition of CBM, since they are made for reliability reasons and no single user of the system would otherwise reimburse the transmission provider for the associated costs.

48. EPSA and Williams request clarification that ATC and AFC calculations should be determined and posted in real-time, not just as planning information, and that the transmission provider be required to post results of its system utilization for ETC. Williams contends that this would augment the transparency deemed critical to a coherent and uniform calculation of ATC by enabling interested stakeholders and the Commission to verify the ATC calculations performed by transmission providers.

Commission Determination

49. The Commission affirms the decision in Order No. 890 to require consistency of all ATC components and certain definitions, data inputs, data exchange and modeling assumptions. We continue to believe such consistency is necessary to reduce the potential for undue discrimination in the provision of transmission service.

50. We disagree with Southern that increasing consistency with respect to the determination of ATC is contrary to reliability. Use of the NERC reliability standards process will, as a matter of course, guard against any unintended reduction in reliability. Nevertheless, we agree that reliability standards cannot address every unique system difference or differences in risk assumptions when modeling expected flows, which necessitates leaving room for limited discretion on the part of the transmission provider. We believe that the ATC requirements in Order No. 890 allow sufficient flexibility so that utilities, working through NERC/NAESB, can develop ATC standards that continue to provide reliability and are compatible with all other mandatory reliability standards or business practices, yet provide discretion where appropriate. If a transmission provider is faced with unique system conditions or modeling assumptions related to firm transmission service reservations[31] that are not addressed in the ATC-related NERC reliability standards, it must make them transparent through its Attachment C filing and the OASIS posting requirements regarding ATC calculation and modeling approach, studies, models and assumptions and implement them consistently for all transmission customers.

51. We deny MidAmerican's request for clarification that AFC values do not need to be converted into ATC postings of control area-to-control area path quantities. As the Commission explained in Order No. 890, our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate.[32] The Commission did not amend that requirement in Order No. 890 and MidAmerican fails to justify doing so now. To the extent MidAmerican or its customers find it beneficial also to post AFC, MidAmerican is free to post both ATC and AFC values. In response to E.ON U.S., however, we clarify that transmission-owning utilities in an RTO region can request waiver of the requirement to convert AFC calculations into ATC for posting purposes in the event the RTO has been granted such a waiver.

52. In response to TDU Systems, we clarify that adjacent transmission providers must coordinate and exchange data and assumptions to achieve consistent ATC values on either side of a single interface. This is applicable to any neighboring transmission providers no matter whether they use the same or different ATC methodologies. We note, however, that the anticipated consistency is for available capability in the same direction across an interface.

53. We clarify in response to NorthWestern that TRM may be used to accommodate the procurement of ancillary services used to provide service under the *pro forma* OATT. We deny as premature EPSA's and Williams' requests for clarification regarding the real-time determination and posting of ATC and AFC values, as well as posting of utilization of transmission provider's own system ETC. In Order No. 890, the Commission required an exchange of the data both for short and long-term ATC/AFC calculation that will increase the accuracy of ATC calculations.[33] The Commission also required that ATC be recalculated by all transmission providers on a consistent time interval, and in a manner that closely reflects the actual topology of the system, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data, and that NERC/NAESB revise the related reliability standard and business practices accordingly.[34] EPSA and William should address their concerns through the NERC and NAESB processes implementing these requirements.

b. Process To Achieve Consistency

54. The Commission directed public utilities, working through NERC and NAESB, to modify the ATC-related reliability standards and business practices in accordance with specific direction provided in Order No. 890. The Commission concluded that the NERC reliability standards development process and the NAESB business standards development process are the appropriate forums for developing

[31] Transmission providers use different assumptions related to the percentage of firm reservations that are actually scheduled and flow.

[32] *See* Order No. 890 at P 211. ATC values must be posted for control area to control area interconnections, paths for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months, and paths for which a customer requests to have ATC or TTC posted. *See* 18 CFR 37.6(b)(1)(i).

[33] *See* Order No. 890 at P 310.

[34] *See id.* at P 301.

consistency in ATC calculations. To that end, public utilities were directed, working through NERC, to modify the ATC-related reliability standards within 270 days after the publication of Order No. 890 in the **Federal Register**, *i.e.*, December 10, 2007. Public utilities were also directed, working through NAESB, to develop business practices that complement NERC's new reliability standards within 360 days after the publication of Order No. 890 in the **Federal Register**, *i.e.*, March 10, 2008.[35]

Requests for Rehearing and Clarification

55. Several petitioners contend that the Commission's direction to public utilities, working through NERC, to modify standards to meet specific ATC requirements is tantamount to dictating reliability standards in violation of FPA section 215.[36] These petitioners assert that system reliability will be best maintained if NERC, having been certified by the Commission as the ERO, is afforded discretion in creating the necessary reliability standards in the first instance prior to submission to the Commission for approval consistent with section 215.[37] EEI and Southern suggest that the Commission give guidance and direction to NERC on how standards should be developed, but not be overly prescriptive. E.ON LSE argues that the Commission should require, or at least permit, NERC to consolidate its ATC development process with its ongoing reliability standards process to develop policies, but should refrain from rewriting any standards developed through that consolidated process.

Commission Determination

56. The Commission affirms the decision in Order No. 890 to rely on the NERC reliability standards development process, and the NAESB business practices development process, to achieve a more coherent and uniform determination of ATC. We disagree that this conflicts with the Commission's obligations under section 215 of the FPA. In Order No. 693, the Commission exercised its authority under FPA section 215 to direct the ERO to modify the existing modeling, data, and analysis (MOD) standards related to ATC calculation, providing guidance consistent with our requirements in Order No. 890. The Commission clarified that, where Order No. 693 identified a concern and offered a specific approach to address the concern, the Commission would consider an equivalent alternative approach provided that the ERO demonstrated that the alternative would address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal.[38] We believe this provides the appropriate flexibility for NERC, while ensuring that the Commission act to remedy the potential for undue discrimination in the calculation of ATC.

c. Applicability to ISOs, RTOs, and Non-Public Utility Transmission Providers

57. The Commission did not require ISO and RTO transmission providers to ''rejustify'' existing provisions in their OATTs that are not affected in a substantive manner by the revisions to the *pro forma* OATT in the Final Rule. However, the Commission did require all transmission providers, including an ISO or RTO, to demonstrate that variations from the tariff modifications required in Order No. 890 continue to satisfy the consistent with or superior to standard. With respect to the application of the ATC requirements of Order No. 890, the Commission noted that ISOs and RTOs would be required to comply with reliability standards developed under FPA section 215.

Requests for Rehearing and Clarification

58. Because Order No. 890 did not exempt ISOs/RTOs from the new ATC standards or curtailment information posting requirements, NYISO asks the Commission to clarify that NERC and NAESB must develop ATC standards and curtailment information posting rules that accommodate ISOs/RTOs. NYISO anticipates that ATC calculations will continue to be of limited significance within its control area, but acknowledges that it does calculate ATC at its external interfaces and also uses ATC to determine the availability of non-firm transmission service, *i.e.*, service for customers that do not wish to be exposed to congestion charges. NYISO states that it, therefore, has an interest and intends to participate in the NERC and NAESB processes developing new ATC standards and curtailment information posting requirements.

59. NYISO contends, however, that stakeholders from traditional systems will have a greater interest in the development of those rules and, as a result, that the NERC and NAESB processes may produce rules that primarily reflect the needs of traditional systems and do not accommodate ISOs/RTOs that are based upon locational marginal pricing of transmission. NYISO argues that Order No. 890 requires NERC and NAESB to develop standards that suit both traditional systems as well as the ISOs/RTOs that cover more than half of the load in the United States. NYISO requests that the Commission expressly state its expectation that the NERC and NAESB processes will produce standards that fulfill Order No. 890's objectives of transparency and inter-regional consistency, yet that are sufficiently flexible to work for ISO/RTO regions.

Commission Determination

60. Order No. 890 requires NERC and NAESB to develop a single set of ATC-related standards that will apply to all transmission providers, including RTOs and ISOs. We understand that the NERC ATC standard drafting team includes representatives from various industry sectors, including RTOs/ISOs, and we encourage NYISO to participate in the standard development process to provide NERC an opportunity to address its concerns. To the extent NYISO feels its concerns are not addressed in this process, it should bring the issue to the Commission's attention on review of the resulting reliability standards.

d. ATC Components

61. In Order No. 890, the Commission adopted certain requirements regarding the components of ATC (*i.e.*, TTC/TFC, ETC, CBM and TRM) necessary to achieve consistency and, in turn, limit the potential for undue discrimination in the calculation of ATC. Petitioners request rehearing and clarification of the Commission's determinations related to ETC, CBM and TRM, which we address in turn.

(1) ETC

62. The Commission adopted the NOPR proposal and directed public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. The Commission determined that ETC should be defined to include committed

[35] The Commission has since extended these compliance deadlines to May 9, 2008, and August 7, 2008, respectively. *See Preventing Undue Discrimination and Preference in Transmission Service,* Notice of Extension of Time, Docket Nos. RM05–17–000, *et al.* (Dec. 6, 2007).

[36] *E.g.,* EEI, E.ON LSE, and Southern.

[37] *Citing* 16 U.S.C. 824o(d)(2) (requiring the Commission to ''give due weight to the technical expertise of the [ERO]'' on reliability matters).

[38] *See Mandatory Reliability Standards for the Bulk Power System,* Order No. 693, 72 FR 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *order on reh'g,* 120 FERC ¶ 61,053 (2007) (Order No. 693–A). Pending completion of the NERC/NAESB standardization process, each transmission provider must perform its ATC-related calculations in accordance with the methodology set forth in Attachment C to its OATT, as revised to comply with Order No. 890.

uses of the transmission system, including (1) native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations,[39] (4) rollover rights associated with long-term firm service, and (5) other uses identified through the NERC process. The Commission determined that ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM.[40] In addition, for short-term ATC calculations, all reserved but unused transfer capability (non-scheduled) must be released as non-firm ATC.

63. The Commission also found that inclusion of all requests for transmission service in ETC would likely overstate usage of the system and understate ATC. The Commission therefore found that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at the POR. The Commission directed public utilities, working through NERC, to develop requirements in MOD–001 that lay out clear instructions on how these reservations should be modeled. The Commission also concluded that some elements of ETC are candidates for business practices instead of reliability standards and directed public utilities, working through NAESB, to develop business practices necessary for full implementation of the MOD–001 reliability standard.

Requests for Rehearing and Clarification

64. TDU Systems contend that, although the Commission defined the ETC component of ATC to include committed uses of the transmission system, it did not clearly identify how requests for transmission service are to be treated. TDU Systems question whether the Commission's use of the term ''committed requests'' is the same as ''confirmed requests'' for service. In order to provide greater clarity, certainty and transparency to the ATC calculation process, TDU Systems ask the Commission to clarify that ''committed requests'' means the same thing as ''confirmed requests,'' as this term is generally understood throughout the industry.

65. TranServ requests clarification that the Commission's statement that all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC was limited to the release of unscheduled firm transmission capability and not intended to require transmission providers to release unscheduled non-firm capability for additional non-firm sales.[41]

Commission Determination

66. The Commission clarifies in response to TDU Systems' request that the reference to ''committed requests'' in Order No. 890 was intended to refer to confirmed transmission service requests. Once a service request has been approved by the transmission provider and confirmed by the transmission customer, it should be taken into account when determining ETC.

67. We also agree with TranServ that the Commission's reference to releasing unused (non-scheduled) transfer capability as non-firm ATC applies to unscheduled firm transmission capability, since all unused non-firm capacity is deemed available to any entity meeting the scheduling requirements. This does not alter the requirement that the transmission provider offer all available capacity, firm or non-firm, as applicable, consistent with our longstanding open access principles.

(2) CBM

68. The Commission directed public utilities, working through NERC and NAESB, to develop clear standards and business practices for how the CBM value is determined, allocated across transmission paths and flowgates, and used. To ensure that CBM is used for its intended purpose, the Commission provided that CBM shall only be used to allow an LSE to meet its generation reliability criteria. The Commission rejected requests to allow CBM to be used to meet reserve-sharing needs, explaining that TRM is the appropriate category for that purpose. Public utilities were directed to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.

69. The Commission clarified that each LSE within a transmission provider's control area has the right to request the transmission provider to set aside transfer capability as CBM for the LSE to meet its historical, state, RTO, or regional generation reliability criteria requirement such as reserve margin, loss of load probability, the loss of largest units, etc. It also determined that LSEs should be permitted to call for the use of CBM, pursuant to conditions established in the reliability standards development process. Public utilities were directed to work through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. The Commission also directed public utilities, working through NERC, to develop clear requirements for allocating CBM to paths and flowgates and concluded that transmission capacity set aside as CBM shall be zero in non-firm ATC calculations.

70. Finally, the Commission required the transmission provider to design their transmission charges so that the class of customers not benefiting from the CBM set-aside, *i.e.*, point-to-point customers, do not pay a transmission charge that includes the cost of the CBM set-aside. Transmission providers were permitted to submit redesigned transmission charges that reflect the CBM set-aside through a limited issue FPA section 205 rate filing. The Commission noted that these filings may be limited to the rate design change only, *i.e.*, they would not require the submission of cost of service data or a revision to the transmission provider's revenue requirement.

Requests for Rehearing and Clarification

71. Duke requests that the Commission clarify that utilities that do not reserve CBM for themselves do not need to make it available to others. Although the Commission required transmission providers to make CBM available to LSEs that request it, Duke argues that the Commission has no authority under FPA section 206 to require transmission providers to do so when they do not use CBM themselves since there is no potential for undue discrimination.

72. With regard to the calculation of CBM, Southern argues that requiring a consistent calculation methodology would be harmful to LSEs because reserve needs vary from area to area. Southern contends that LSEs should be allowed the flexibility to establish CBM on a per-interface basis so that CBM use will be commensurate with expected system conditions, topography, and available capacity markets. Southern states, for example, that small LSEs typically have fewer internal resources than larger LSEs and therefore need

[39] The Commission explained that the reference to ''appropriate point-to-point reservations'' meant that reservations accounted for under ETC depend on the firmness and duration of the reservation. The Commission stated that the specific characteristics should be developed in the reliability standard.

[40] TRM also includes such things as loop flow and parallel path flow.

[41] *Citing* Order No. 890 at 244, 389.

more CBM. Southern contends that a consistent methodology could result in higher infrastructure cost, place system reliability at risk, and ultimately remove the economic benefit associated with CBM.

73. Southern also argues that development of a ''one-size-fits all'' methodology for the calculation of CBM would be impossible due to varying regional and state mandates governing generation adequacy issues. Southern contends that such a mandate, if applied to a transmission provider's native load customers that are under varying regional and state resource adequacy requirements, would amount to a regulation of reserve adequacy which is outside of the Commission's jurisdiction. Southern adds that this would implicate (and may violate) the reliability provisions of FPA section 215 and the native load protections of FPA section 217.

74. TDU Systems request that the Commission clarify, or grant rehearing, that if a transmission provider does not accommodate reserve-sharing arrangements for its load-serving transmission customers as TRM, then it must allow access to the CBM set-aside for reserve-sharing purposes. TDU Systems are concerned that some transmission providers do not use TRM set-asides, but rather use a CBM-approach to reserving capacity across interfaces for reserve-sharing arrangements. In such cases, TDU Systems state that LSEs needing access to interface capacity to accommodate reserve-sharing arrangements may not be able to obtain that capacity if the Commission limits such usage to TRM. TDU Systems contend that transmission providers set aside interface capacity to serve their retail native load in the case of both generation emergencies and economic transactions and that comparability demands the same for the reserve-sharing arrangements for LSEs.

75. With regard to cost recovery of the CBM set-aside, Southern argues that CBM is a component of network service that is already paid for by network customers and native load through their bearing a load-ratio share responsibility for the costs of the transmission system. Southern contends that CBM is used as a network reservation of resources used to service network and/or native load under certain conditions. Southern argues that a network customer's cost responsibility is based upon its load, not its designation of network resources and, therefore, the network customer is already bearing CBM-related costs through its load ratio share responsibility.

76. As a result, Southern concludes that point-to-point customers are not paying for CBM capacity and, instead, are paying their appropriate share of the total transmission system cost based upon their reservations of capacity. Southern states that Commission policy requires network customers and native load to bear the costs of both the capacity they use and any capacity that is not reserved by point-to-point customers.[42] Southern argues that the Commission's finding in Order No. 890 that point-to-point customers are inappropriately bearing the costs of CBM represents an unexplained departure from Order No. 888-A.

77. Southern also contends that this ruling will result in an inconsistency within the *pro forma* OATT, requiring incremental cost responsibility for network customers to utilize one particular type of external resource or off-system purchase, *i.e.*, the utilization of CBM. Southern argues that this conflicts with the structure of network service under the *pro forma* OATT, which allows the network customer to utilize the interfaces for both external designated network resources and off-system opportunity purchases without additional charge. Southern also contends that requiring network customers to pay for CBM on the same basis as firm point-to-point service disadvantages the use of CBM since interface capacity could only be used on an emergency basis and therefore is not considered firm service for the purpose of designating off-system system resources.

78. Southern goes on to assert that the Commission's premise that point-to-point customers are not benefiting from CBM is incorrect. Southern notes that under normal conditions the transfer capability reserved as CBM is made available for non-firm use by other customers. Southern notes also that long-term point-to-point customers benefit from the non-firm point-to-point use of that transfer capability because associated revenues are included as revenue credits in the numerator of the OATT rate calculations to reduce charges to long-term firm point-to-point customers.

79. If the Commission does not reverse its decision in Order No. 890 regarding the redesign of transmission charges, Southern seeks clarification regarding how the CBM set-aside should be treated for ratemaking purposes since it does not represent additional load. Southern notes that the potential for long-term customers to receive a rate benefit from the non-firm point-to-point use of the set-aside raises the potential for them receiving a double credit. Southern also suggests that the Commission defer the new rate design filing until after NERC has adopted ATC standards under MOD–001.

80. EEI and Idaho Power raise similar concerns, asking the Commission to clarify that, when the transmission provider modifies its rate design for point-to-point transmission service, it also may propose a rate design modification to ensure that it recovers from network and native load customers any reduction in revenues resulting from the change in the rates for point-to-point service. Duke contends that allocating costs of the CBM set-aside through a downward revision to point-to-point rates would have the effect of allocating costs to native load and network customers for a service that is not taken. EEI and Idaho Power argue that the Commission should allow transmission providers to modify their rates for other services in order to prevent under-recovery of their costs of service or inappropriately shifting costs to native load customers. EEI also requests the Commission to clarify that the rate design change may take into consideration the fact that transmission providers credit against the cost of service revenues received from short-term and non-firm transmission service provided using capacity that is set aside for CBM to ensure that long-term firm point-to-point customers do not receive a double credit for the use of CBM capacity.

81. EEI requests further clarification regarding how a transmission provider should modify unit charges that are established by settlement. EEI argues that transmission providers should not be required to make an entirely new cost-of-service filing and, instead, should be permitted to reduce its rates for firm point-to-point service by the ratio of its current transmission load and reservations without the CBM set-aside to its transmission load and reservations plus the CBM set-aside.

Commission Determination

82. The Commission clarifies in response to Duke that utilities do not need to make CBM available to LSEs on their system if the utilities do not reserve for themselves CBM or its equivalent. Comparability only requires transmission providers to make CBM available when they set aside for themselves transfer capability to meet generation reliability criteria.[43] In order

[42] *Citing* Order No. 888–A at P 30,220.

[43] We note that Duke states, in its Attachment C compliance filing, that it has set CBM on all of its

Continued

to provide transparency and consistency regarding the use of CBM, public utilities, working through NERC, must develop clear standards for how CBM is determined, allocated across transmission paths, and used.[44]

83. The Commission did not mandate a particular methodology for allocating CBM over transmission paths and flowgates in Order No. 890. We therefore reject Southern's argument that development of a consistent methodology for calculating CBM would be harmful to LSEs because reserve needs vary from area to area. While we expect the NERC and NAESB process to produce a consistent and transparent process for setting aside and allocating CBM based on LSE requests, we decline to prescribe a specific method for how CBM should be obtained or allocated or otherwise determine the amount of capacity that the transmission provider has to set aside in response to requests from multiple LSEs.

84. We disagree that a consistent CBM methodology that allows LSEs access to historically used resources would impair reliability, conflict with the rights of native load under FPA section 217, or otherwise implicate varying regional and state mandates governing adequacy issues. In any event, it is premature to consider these questions since NERC and NAESB have yet to complete their work on the reliability standards and business practices. We also disagree with Southern that a consistent CBM methodology will remove the economic benefit associated with CBM. Rather, a consistent methodology for determining how the CBM value is determined, allocated, and used will remove excess discretion that transmission providers previously had and allow all LSEs to have the benefits associated with CBM.

85. Regarding TDU Systems' request to use CBM for reserve-sharing arrangements, we reiterate that TRM is the appropriate category for reserve-sharing arrangements and that CBM is to meet verifiable generation reliability criteria in times of emergency generation deficiencies.[45] As the Commission explained in Order No. 890, TRM may be used for other transmission-related uncertainties as well.[46] Because the transmission provider may set aside transfer capability for TRM to operate the system reliably, we reject TDU Systems' request to use CBM for reserve-sharing purposes.

86. With regard to cost recovery of the CBM set-aside, we affirm the decision in Order No. 890 to require transmission providers to design their transmission charges to ensure that the class of customers not benefiting from the CBM set-aside, *i.e.*, point-to-point customers, do not pay a transmission charge that includes the cost of the CBM set-aside. Only network customers and the transmission provider on behalf of its native load may request that transmission capacity be set aside as CBM and, therefore, only those users of the system should bear its costs. We disagree with Southern that, because CBM is used by network customers, all the costs associated with CBM are already borne by network customers through their load ratio share responsibility. As Southern acknowledges, the rates for point-to-point service are also calculated based on a share of total transmission system cost. If the costs associated with CBM are not excluded from the universe of costs allocated to all point-to-point customers, then every point-to-point customer will end up paying a portion of those costs. The Commission's rate design ruling is therefore consistent with, not contrary to, the Commission's directive in Order No. 888–A for network customers and native load to bear the cost of capacity not used by point-to-point customers.[47]

87. We acknowledge, as Southern claims, that point-to-point customers do reap some indirect benefits from the CBM set-aside in that related capacity that is not used is made available on a non-firm basis and that, in turn, can generate revenues that are credited to the transmission cost of service to the benefit of point-to-point customers. We do not believe this justifies charging all point-to-point customers for the cost of the CBM set-aside. These costs should instead be allocated to the entities that have the exclusive right to request the set-aside in the first instance. We agree that, in certain circumstances, this may necessitate modification of other rate design elements to ensure that costs are appropriately allocated and that the transmission provider fully recovers any reduction in revenues resulting from the change in the rates for firm point-to-point service. Nothing in Order No. 890 precludes transmission providers from proposing modification of rates for other services (such as network service) as necessary to recover CBM-related costs previously paid by point-to-point customers. Similarly, we expect that transmission providers would address in their rate design filings any possibility for particular customers to receive an inappropriate credit for non-firm use of capacity set aside for CBM.

88. We disagree that requiring transmission providers to design their rates to properly allocate CBM-related costs conflicts with the nature of network service or disadvantages network customers using CBM. Under the *pro forma* OATT, transfer capability is made available for network resource designations and firm point-to-point reservations on a non-discriminatory basis. It is therefore appropriate to design rates so that network customers and point-to-point customers pay rates based on the service available to each.

89. We decline to defer the filing of CBM-related rate design proposals until completion of the NERC/NAESB standardization process. To the extent a transmission provider's rates currently collect the costs associated with the CBM set-aside from point-to-point customers, those rates must be redesigned in accordance with Order No. 890. We acknowledge, however, that the on-going NERC and NAESB standardization processes may result in CBM being set aside and used differently in the future. To the extent such changes implicate the allocation of costs among those that are eligible to request or use the set-aside, the transmission provider should file with the Commission any necessary rate changes to ensure that CBM costs continue to be allocated appropriately.

90. Finally, we decline to address here what changes may be necessary to a particular rate settlement in order to ensure that costs associated with the CBM set-aside are allocated properly. All proposals to allocate CBM costs will be considered on a case-by-case basis, whether they involve rates stated in a settlement or otherwise.

(3) TRM

91. The Commission required public utilities, working through NERC, to complete the ongoing process of modifying TRM-related reliability standards (MOD–008 and MOD–009). To guide NERC and NAESB in the process of drafting TRM-related standards and business practices, the Commission explained that transmission providers may set aside TRM for (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in

interfaces to zero because it uses short-term line ratings (where available), which yields an operating margin that may be used for unexpected conditions or inaccuracies in data. *See* Compliance filing of Duke Energy Carolinas, Docket No. OA07–82–000 (Sep. 10, 2007); Open Access Transmission Tariff of Duke Energy Carolinas, LLC, FERC Electric Tariff Fifth Rev. Vol. No. 4, Original Sheet 170H. The Commission will address the merits of that practice in Docket No. OA07–82–000.

[44] Order No. 890 at P 256, 259.

[45] *See id.* at P 264.

[46] *See id.* at P 273.

[47] *See* Order No. 888–A at 30,220.

transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process. To the extent capability is needed for transmission of shared reserves, the Commission stated that it must be included in TRM, although the Commission did not mandate the use of reserve sharing groups.

92. Each transmission provider was required to calculate, and allocate on the paths and flowgates, the aggregate TRM value for all LSEs within its area. Public utilities also were directed, working through NERC, to establish an appropriate maximum TRM. The Commission expressed support for NERC's plan to revise existing reliability standards for TRM to require clear documentation of the TRM calculation, to ensure full transparency. In addition, the Commission required each transmission provider to make available all underlying documentation, including work papers and load flow base cases, used to determine TRM, to any transmission customer and LSE within its control area, subject to a confidentiality agreement,[48] if necessary. Because load, facility loadings, and other uncertainties constantly deviate, the Commission did not require that TRM set-aside capacity be sold on a non-firm basis. The Commission explained that any request for regional difference from the applicable TRM reliability standards must take place through the NERC reliability standards development process.

Requests for Rehearing and Clarification

93. Duke asks the Commission to clarify that it intended NERC to develop a methodology to calculate a maximum TRM number, not to put an actual number in the reliability standard, arguing that requiring an actual number would overstep the bounds of FPA section 215. Southern argues that NERC must be allowed flexibility to develop appropriate TRM methodologies so that the use of TRM will be commensurate with expected system conditions, topography, and available capacity markets. Southern contends that setting a maximum amount of TRM would overlook the physical realities of the differing system configurations that constitute the electrical system. Southern argues, in particular, that the percentage ratings reduction proposed would be poorly suited as a reliability margin since individual line flows can change by very large percentages for single contingency events.

Commission Determination

94. The Commission clarifies that NERC was not directed to identify an actual number or a particular methodology to include in the TRM standards, MOD–008–0 and MOD–009–0. The Commission's intent was to require NERC and NAESB to include consistent criteria and guidelines in the calculation and uses of TRM by transmission providers.[49] Likewise, in response to Southern's concern regarding flexibility to use something other than the ratings reduction method discussed in Order No. 890, we clarify that the ratings reduction method is only an example of a simple method that could be used.[50] Our intent is not to prohibit a transmission provider from using a more sophisticated method, so long as it is consistent with the reliability standards developed by NERC.

e. Modeling, Assumptions and Input Data

95. The Commission directed public utilities, working through NERC, to modify the reliability standards MOD–010 through MOD–025 [51] to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that these models are up to date. The Commission stated that the models should be updated and benchmarked to actual events.

96. The Commission also required transmission providers to use consistent data and assumptions underlying operational planning for short-term ATC and expansion planning for long-term ATC calculation, to the maximum extent practicable. The Commission explained that such data and assumptions include, for example, (1) load levels, (2) generation dispatch, (3) transmission and generation facilities maintenance schedules, (4) contingency outages, (5) topology, (6) transmission reservations, (7) assumptions regarding transmission and generation facilities additions and retirements, and (8) counterflows. The Commission directed public utilities, working through NERC, to modify ATC standards to achieve this consistency.

Requests for Rehearing and Clarification

97. Entergy requests that the Commission acknowledge that the benchmarking of ATC calculations to real-time ATC values is only one piece of information to be used to evaluate ATC practices. Entergy agrees that such updating and benchmarking can provide information related to ATC/AFC calculations, but states that differences between the models used to calculate ATC/AFC and actual events in fact are going to occur. Entergy contends that the purpose of the ATC/AFC models is not to forecast actual operating conditions, but instead to reflect the physical transmission rights that have been previously granted and to determine if additional physical rights may be granted.[52] Entergy argues that benchmarking may be helpful when evaluating ATC, but it will not tell the whole story.

98. TDU Systems request that the Commission explicitly state that assumptions regarding loop flows must be consistent for ATC calculation and planning purposes, within the respective timeframe. TDU Systems argue that consistency in modeling the effects of those loop flows is necessary to ensure that neighboring transmission systems have accurately calculated ATC not only on their own systems but also on their interfaces with other systems. TDU Systems also ask that the Commission clarify that the assumptions and data to be used in ATC modeling must include the native load service obligations of LSEs as well as the transmission provider's native load.

Commission Determination

99. The Commission clarifies in response to Entergy that the models used by the transmission provider to calculate ATC, and not actual ATC values, must be benchmarked. The

[48] The confidentiality agreement may appropriately restrict the sharing of sensitive information with customer personnel that are involved only in transmission functions, as opposed to merchant functions.

[49] *See* Order No. 890 at P 273.

[50] *See id.* at P 275.

[51] The MOD–010 through MOD–025 reliability standards establish data requirements, reporting procedures, and system model development and validation for use in the reliability analysis of the interconnected transmission systems.

[52] Entergy asserts that actual conditions will and should deviate from ATC/AFC models for numerous reasons. Entergy states that transmission operators are constantly monitoring their systems and taking actions to ensure that system constraints are mitigated well before real-time, including modifications to transmission outage plans, generator outage plans, and daily unit commitment plans. Entergy contends that those actions could, for example, make a flowgate that months ahead of time was predicted to be loaded at 100 percent to be loaded less than 50 percent in real-time. Entergy also notes that many transmission customers only use all of their transmission rights a small percentage of the time and, in any event, actual operating ATC will not perfectly match posted ATC since, for example, the level of mandatory purchases from qualifying facility (QF) can affect real-time ATC.

Commission is concerned with the level of accuracy of the models and, therefore, directed in Order No. 890 that the models be updated and benchmarked to actual events. If models are not sufficiently accurate, then ATC/AFC calculations will not generate correct results, undermining the benefits of increased consistency and transparency of ATC calculations. With regard to discrepancies between actual and modeled ATC values, the Commission directed the ERO in Order No. 693 to modify MOD–014–0 through the reliability standards development process to require that actual system events be simulated and, if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy.

100. We agree with TDU Systems that assumptions regarding loop flows in calculating ATC must be consistent with those used for planning purposes within the respective timeframes. We also agree that loop flow impact in ATC calculation should not be restricted to the transmission provider's control area. Loop flows that occur in the power system must be included in the load flow models that simulate power system conditions. Loop flows affecting ATC calculation should be taken into account consistently by using the same models and assumptions as used for the planning of the system. With regard to modeling LSE uses of the system, we clarify that each transmission provider must include the native load service obligations of LSEs as well as the transmission provider's own load in modeling assumptions and data used for ATC calculation.

f. ATC Calculation Frequency

101. The Commission directed public utilities, working through NERC and NAESB, to revise reliability standard MOD–001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. The Commission stated that this process must also consider whether ATC should be calculated more frequently for constrained facilities.

Requests for Rehearing and Clarification

102. Powerex asks the Commission to clarify that transmission providers are required to update their ATC calculations when they receive new data otherwise required to be posted under the requirements of Order No. 890, such as updated load forecasts. Powerex argues that the standards adopted through the NERC and NAESB processes should serve only as minimum or ''no less frequent than'' requirements. In Powerex's view, the specification of consistent intervals for ATC calculations should not prohibit or deter transmission providers from calculating and posting ATC on a more frequent basis as new data becomes available, particularly in light of the Commission's goal in Order No. 890 to make the ATC calculation process more transparent to customers.

103. Southern asks the Commission to clarify that ATC, not TTC, must be recalculated at consistent time intervals. Although the Commission referenced ATC in Order No. 890, Southern contends that the associated data and assumptions mentioned by the Commission (generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data) relate to TTC. Southern argues that ATC is the appropriate reference because it can be calculated automatically with relative ease and frequency. In comparison, Southern states that TTC requires much more complex power flow analyses and should not be driven by changes in parameters without expert review. Southern contends that the calculation frequency requirements established by the Commission would result in constantly changing values if applied to TTC, with little time, if any, for the necessary review.

Commission Determination

104. The Commission agrees with Powerex that the standards adopted through the NERC and NAESB processes should serve as minimum or ''no less frequent than'' requirements to recalculate ATC. Transmission providers also must update their ATC calculation when they receive substantial and material changes in data, such as updated load forecasts, changes in topology and dispatch patterns, which may be more frequent than the NERC and NAESB standards would otherwise require. In the absence of substantial and material changes in data, transmission providers are not required to update ATC on a more frequent basis than the minimum frequency that the NERC and NAESB standards require, once implemented. The Commission will consider the adequacy of the time frame for ATC updates on review of these standards.

105. In response to Southern, we reiterate that Order No. 890 directed revisions to reliability standard MOD–001 to require that ATC, not TTC, be recalculated at consistent time intervals.[53] However, system topology or other changes such as transmission outages, load forecast, interchange schedules, transmission reservations, or facility ratings, and other necessary data that affect ATC may of course impact one or more of the components of ATC, including TTC. While we agree with Southern that TTC requires more involved power flow analyses, the transmission provider should consider whether any changes in system topology, contingency outages, or other factors are substantial enough to merit recalculation of TTC.

2. Transparency

106. In Order No. 890, the Commission adopted a number of requirements in order to improve the transparency of ATC calculations. Some of these reforms applied to the *pro forma* OATT, including a requirement that each transmission provider include in Attachment C to its OATT more descriptive information concerning its ATC/AFC calculation methodology. Other reforms applied to information posted on OASIS, including data related to the calculation of ATC and TTC, changes in the ATC/TTC values, disclosure of Critical Energy Infrastructure Information (CEII), and the posting of additional ATC-related data. Petitioners have requested rehearing and clarification of certain of these requirements, which we address in turn.

a. OATT Transparency—Attachment C

107. To increase transparency regarding ATC calculations, the Commission directed each transmission provider to set forth its ATC calculation methodology in Attachment C to its OATT. The Commission required that each transmission provider's Attachment C must, at a minimum: (1) Clearly identify which of the NERC-approved methodologies it employs (*e.g.*, contract path, network ATC, or network AFC); (2) provide a detailed description of the specific mathematical algorithm the transmission provider uses to calculate firm and non-firm ATC for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule), and planning horizon (beyond the operating horizon); (3) include a process flow diagram that describes the various steps that it takes in performing the ATC calculation; (4) set forth a definition of each ATC component (*i.e.*, TTC, ETC, TRM, and CBM) and a detailed explanation of how

[53] *See* Order No. 890 at P 301.

each one is derived in both the operating and planning horizons; and (5) document their processes for coordinating ATC calculations with their neighboring systems.

108. The Commission concluded that Attachment C must provide an accurate documentation of processes and procedures related to the calculation of ATC, not the actual mathematical algorithms, which instead should be posted on their Web site with the link noted in the Attachment C. The Commission noted that a transmission provider may require a confidentiality agreement for CEII materials, consistent with our CEII requirements, or may otherwise protect the confidentiality of proprietary customer information. The Commission also required transmission providers to file a revised Attachment C to incorporate any changes in NERC's revised reliability standards and NAESB's business practices related to ATC calculations, as requested by the Commission in Order No. 890, within 60 days of completion of the NERC and NAESB processes.

Requests for Rehearing and Clarification

109. MidAmerican objects to the Commission's decision to require a process flow diagram to be included in Attachment C, suggesting instead that each transmission provider post this information on its Web site as an alternative. MidAmerican contends that process flow diagrams demand large amounts of computer capacity and that management of and electronic transmittal of its OATT would become difficult if process flow diagrams were required for other elaborate and important tasks throughout the tariff, such as the transmission service request procedure or the generation interconnection procedure. MidAmerican argues that providing a web link on OASIS would achieve the Commission's transparency objective and expeditiously provide those that wish to navigate through a process diagram a direct access to the document. At a minimum, MidAmerican asks that the Commission accept an internet posting of the diagram with the web address published in Attachment C.

110. Southern requests clarification as to whether the Commission intends for transmission providers to make two filings of ATC methodologies (*i.e.*, one when the Order No. 890 becomes effective and another when the NERC and NAESB processes are completed) or just one filing of such methodologies (*i.e.*, a single filing when the NERC and NAESB processes are completed). Southern argues that only one filing should be required, to be made within 60 days after the NERC and NAESB processes are completed. Southern contends that requiring a premature filing before those processes are complete would waste transmission providers' resources in preparing those filings and the Commission's resources in reviewing them.

Commission Determination

111. The Commission denies MidAmerican's request to permit a transmission provider to post on its Web site a process flow diagram and provide a web address in Attachment C, instead of providing the process flow diagram as a part of the Attachment C. A link to a Web site is not the equivalent of inclusion in the transmission provider's OATT, leaving the Commission unable to enforce use of the process flow diagram and the public with potentially more limited notice of any changes to the process flow diagram. The transparency and enforceability benefits of including the flow diagram in the tariff outweigh any potential filing burden. Therefore, we affirm our determination in Order No. 890 that a process flow diagram must be filed with OATT Attachment C, and that any change of the processes or data information identified by the process flow diagram must trigger an update of the process flow diagram and the filing of the revised OATT, Attachment C.

112. In response to Southern, Order No. 890 specifically required transmission providers to submit an intermediate filing within 180 days after the publication of the order in the **Federal Register** in order to provide transparency of the transmission provider's existing ATC calculation methodologies. In compliance with that requirement, a number of transmission providers, including Southern, submitted Attachment C compliance filings on September 11, 2007. The immediate transparency benefits of these filings will be supplemented by a revised filing following completion of the NERC and NAESB standardization processes. We do not believe the intermediate filing represented an undue burden to the transmission providers, as it was no more than a documentation of existing practices.

b. OASIS

(1) ATC/TTC Posting Requirements

113. The Commission concluded that transmission providers must continue to comply with existing ATC-related posting requirements, as supplemented by Order No. 890. To that end, the Commission stated that it would maintain a requirement for transmission providers to make available, upon request, all data used to calculate ATC and TTC for any constrained paths and any system planning studies or specific network impact studies performed for customers. Transmission providers were also directed to continue to post a list of such studies on OASIS. The Commission required the additional posting of, at a minimum, a list of all system impact studies, facilities studies, and studies performed for the transmission provider's own network resources and affiliated transmission customers, with those studies to be made available upon request. The Commission noted that appropriate procedures to accommodate CEII concerns should be developed to ensure eligible entities with a legitimate interest in transmission study data can receive access to it. The Commission required that the studies be made available for five years, consistent with data retention requirements pertaining to denial of service requests.

Requests for Rehearing and Clarification

114. MidAmerican requests clarification with regard to the interaction of the data availability obligation under Order No. 890 and the Commission's Standards of Conduct with respect to information requests made by affiliated transmission customers. In order to provide comparable transmission service, MidAmerican argues that data must be available in all circumstances. If the Commission does not clarify that this is the case, MidAmerican requests rehearing of this provision so that comparable information can be made available at all times.

Commission Determination

115. The Commission clarifies that all data used to calculate ATC and TTC for any constrained paths and any system planning studies or specific network impact studies performed for customers are to be made available on request, regardless of whether the customer is non-affiliated or affiliated with the transmission provider. To the extent the requesting party is an affiliate, the Standards of Conduct would require that data provided to the affiliate be simultaneously posted on the transmission provider's OASIS or Web site, as applicable.[54]

(2) ATC/TTC Narrative Explanation

116. The Commission retained existing posting requirements for unconstrained paths and amended its regulations relating to data posted for

[54] *See* 18 CFR 358.5.

constrained paths. Specifically, the Commission required transmission providers to post a narrative when a monthly or yearly ATC value changes as a result of a 10 percent change in TTC on constrained paths. Posted information must include both the (1) specific events which gave rise to the change and (2) the new values for ATC on that path (as opposed to all points on the network). The Commission also required the posting of a narrative with regard to monthly or yearly ATC values when ATC remains unchanged at a value of zero for a period of six months or longer.

Requests for Rehearing and Clarification

117. E.ON U.S. argues that the posting of a narrative explanation for changes in ATC resulting from changes in TTC is unduly burdensome and, in any event, would not provide transmission customers with any meaningful information. E.ON U.S. contends that, using the new process for calculating TTC, a transmission provider would have to calculate the value for each horizon model and compare it to values in the previous hour in order to implement the posting requirement. Where those values change by more than 10 percent, E.ON U.S. states that the transmission provider will have to examine individually each changed parameter to assess its contribution to the change. E.ON U.S. contends that, for its system, the list of parameters to be evaluated would include generation dispatch, system configuration, loads, and net interchanges of which there can be dozens or even hundreds per hour. E.ON U.S. argues that this would take 24 engineers to monitor the E.ON U.S. system alone, costing millions of dollars per year.

118. Southern requests that the Commission clarify that the required narratives do not need to list each and every circumstance or occurrence that impacts TTC values from the previous month or year, stating that such a list would likely be voluminous because of the many conditions that affect TTC. Southern instead suggests that transmission providers list the primary reasons for the change in TTC to the extent they are known. Southern contends, for example, that an appropriate reason for such changes would be a new updated monthly model, arguing that it would not be practical to determine how much TTC may change from each outage, service commitment or other parameter change incorporated in an updated model.

119. Southern also requests that the Commission clarify where the transmission provider should post these narrative explanations and in what form. Southern proposes that this information be posted on OASIS via a template and data element that is to be defined by a NAESB standard, incorporated into a revised Standards and Communications Protocol document, and subsequently adopted by the Commission.

120. TDU Systems argue that the Commission has set too high of a threshold for reporting changes in ATC/TTC, arguing that the triggering requirement should be a 10 percent decrease in ATC, rather than a 10 percent change in TTC. TDU Systems contend that TTC is a large enough number that using a decrease of 10 percent in TTC as a trigger for requiring a narrative explanation to be posted will result in very few narrative explanations posted, thereby defeating the purpose of the requirement.

121. PJM seeks clarification of the posting requirement as applied to transmission providers using an AFC calculation method. PJM states that TTC is an output from, not an input to, its AFC/TTC calculations and therefore the literal terms of the regulations do not make sense as applied to PJM. PJM proposes to post a narrative explanation for the reason for daily changes in ATC or TTC values as a result of changes in AFC inputs (*i.e.*, transmission outages, generator outages, load forecast, and model updates) in the event the resultant ATC or TTC value changes by 10 percent or more, requesting that the Commission confirm that this approach would appropriately adapt the Order No. 890 posting requirement to a system such as PJM that uses an AFC methodology. Alternatively, if the Commission does not wish to address PJM's manner of implementation of this revised regulation in the context of rehearing/clarification of Order No. 890, PJM asks that the Commission allow PJM, and other similarly situated transmission providers, to address this issue in their Order No. 890 tariff compliance filings. In that event, PJM asks that the Commission clarify only that such transmission providers may continue their existing practices until the Commission acts on their compliance filings.

122. TDU Systems also argue that the six-month trigger for posting an explanation for zero ATC values is unsupported, asking instead that transmission providers be required to post a narrative explanation of zero ATC values any time those values remain at zero for a period that affects access in a practical way, *e.g.*, a day for daily service, two business days for weekly service, five business days for monthly or yearly service. TDU Systems contend that a transmission system where ATC values remain at zero for any length of time raises serious concerns as to the adequacy of the system and the need for significant upgrades, and simply posting a zero value for ATC does not provide market participants with an understanding of what is happening on the system.

Commission Determination

123. The Commission affirms the decision in Order No. 890 to require transmission providers to post a brief, but specific, narrative explanation of the reason for a change in monthly or yearly ATC values on a constrained path as a result of a change in TTC of 10 percent or more. As the Commission explained, this will limit the number of ATC changes for which a narrative will be required.[55]

124. We believe that E.ON U.S. overestimates the burden of complying with this requirement. Since TTC standardization is ongoing, it is impossible to identify with precision the steps that will need to be taken to comply with the posting requirement. The appropriate forum to raise concerns regarding the burden of particular TTC calculation requirements is in the NAESB standards development process. In any event, we would expect that the posting of narratives for changes in monthly and yearly ATC values as a result of a 10 percent change in TTC will be triggered mainly by topology changes resulting from transmission lines and generator in-service status, as well as new facilities additions, that are reported on OASIS.

125. We clarify in response to Southern that transmission providers do not need to list each and every circumstance or occurrence that impacts TTC values from the previous month or year and, instead, may list the primary events that give rise to the update. Again, we expect that TTC changes will generally result from topology changes and, therefore, the primary reasons for an update would be changes in schedules of transmission or generation additions, prolonged outages, or changes in maintenance schedules causing a TTC change of 10 percent. We agree with Southern that the transmission provider should post these narrative explanations on OASIS via a template and data element that is to be defined by NAESB. We direct transmission providers, working through NAESB, to develop the OASIS functionality necessary for such postings. Pending completion of this

[55] *See* Order No. 890 at P 369.

work by NAESB, we direct transmission providers to post these narrative explanations as comments on OASIS.

126. We deny TDU Systems' request to change the triggering requirement to a 10 percent decrease in ATC. In Order No. 890, the Commission relaxed the ATC narrative reporting requirements proposed in the NOPR due to concerns that the posting of those narratives would become burdensome. We believe the Commission struck the right balance by requiring the posting of narratives only when there is a change in TTC of 10 percent or more and disagree that more limited postings defeats the purpose of the posting obligation.

127. In response to PJM, we reiterate that all transmission providers must comply with this posting requirement. Transmission providers using an AFC calculation method that does not base changes in ATC on changes in TTC may comply with this requirement by posting narrative explanations of the reasons for changes in AFC values as a result of changes in AFC inputs that cause ATC or TTC to change by 10 percent or more. We direct each transmission provider that employs the AFC calculation methodology to provide a statement in the compliance filing required in section II.C describing how the narrative is derived for ATC/TTC postings or, if such information was provided in a prior compliance filing, a reference to that filing.

128. We also deny TDU Systems' request to require transmission providers to post a narrative explanation any time ATC values remain at zero for a day for daily service, two business days for weekly service, five business days for monthly or yearly service. The Commission concludes that a six-month trigger for monthly or yearly ATC values more appropriately balances the benefits of increased transparency for the Commission and customers against the burden on transmission providers to make such postings. If the frequency of these postings proves inadequate, the Commission can revisit this requirement in a future order.

(3) CEII

129. The Commission acknowledged in Order No. 890 that certain data and studies required to be made public may contain CEII and that the Commission has a responsibility to protect that information. In order to provide transparency and avoid undue delays in providing information to those with a legitimate need for it, the Commission required that transmission providers establish a standard disclosure procedure for CEII required to be disclosed in Order No. 890. The Commission stated that transmission providers will be responsible for identifying CEII and facilitating access to it for appropriate entities and the Commission will be available to resolve disputes if they arise.

130. With regard to procedures to access CEII, the Commission noted that transmission customers already have digital certificates or passwords to access publicly restricted transmission information on OASIS. The Commission suggested that transmission providers could set up an additional login requirement for users to view CEII sections of the OASIS, requiring users to acknowledge that they will be viewing CEII and to sign a nondisclosure agreement at the time the customer obtains access to that portion of the OASIS. The Commission explained that only information that meets the criteria for CEII, as defined in section 388.113 of the Commission's regulations,[56] should be posted in this section of the OASIS.

Requests for Rehearing and Clarification

131. E.ON U.S. contends that the Commission should not allow posting of CEII on OASIS, arguing that information is designated as CEII because it relates to the integral operations of the nation-wide power grid and that, with access to this information, a terrorist or other bad actor could inflict real, substantial harm on the power grid. E.ON U.S. states that posting CEII on a transmission provider's OASIS, a Web site that is openly connected to the internet, will impair the transmission provider's ability to adequately protect this information, even with password protection. E.ON U.S. suggests there are other ways of providing transmission customers with such CEII, such as individual meetings upon request.

132. New York Transmission Owners request that transmission providers be authorized to determine, on a case-by-case basis, the specific level and amount of CEII that a requesting customer may obtain. New York Transmission Owners argue that a terrorist seeking to harm our country's energy infrastructure will not likely be concerned with having to sign a confidentiality agreement or obtain multiple passwords.

Commission Determination

133. We agree with E.ON U.S. that posting CEII on OASIS may not provide adequate protection of CEII and that transmission providers may therefore develop other standard disclosure procedures to provide relevant CEII to transmission customers on a timely basis. The Commission did not require CEII postings on OASIS in Order No. 890 and, instead, discussed use of OASIS as one potential disclosure mechanism.[57] The Commission required transmission providers to establish a standard procedure for disclosing relevant CEII on a timely basis, but did not specify a particular disclosure mechanism.

134. Similarly, transmission providers may determine on a case-by-case basis the specific level of CEII a customer may obtain, provided that the information is made available to appropriate recipients on a timely basis. If a transmission provider chooses to post CEII on a protected section of its OASIS, the transmission provider can and should verify the identity of transmission customers who access that information as it would for any confidential information.

(4) Additional Data Posting

135. The Commission also required transmission providers to post on OASIS metrics related to the provision of transmission service under the OATT. Specifically, non-ISO/RTO transmission providers were directed to post (1) the number of affiliate versus non-affiliate requests for transmission service that have been rejected and (2) the number of affiliate versus non-affiliate requests for transmission service that have been made. This posting must detail the length of service request (*e.g.*, short-term or long-term) and the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The Commission stated that the affiliate posting requirements do not apply to ISOs and RTOs since they do not have any affiliates.

136. The Commission also required transmission providers to post their underlying load forecast assumptions for all ATC calculations and to post, on a daily basis, their actual daily peak load for the prior day and load forecasts and actual daily peak load for both system-wide load (including native load) and native load. ISOs and RTOs are required to post this load data for the entire ISO/RTO footprint and for each LSE or control area footprint within the ISO/RTO.

Requests for Rehearing and Clarification

137. E.ON LSE requests clarification whether the requirement in section 37.6(e)(2) of the Commission's regulations to post information regarding denials of service applies to denials of requests. Washington IOUs

[56] 18 CFR 388.113.

[57] *See* Order No. 890 at P 404.

request clarification on the requirement to post information regarding transmission service requests from affiliates, stating that it is not clear what the Commission means by ''requests for transmission service.'' They suggest that the reference could be to requests for transmission service by affiliated merchant or trading entities or requests for transmission service by the transmission provider's merchant function, including requests to designate or undesignate network resources and requests to procure secondary network service to serve native load.

138. TDU Systems request that the Commission reconsider its decision to exempt RTOs and ISOs from the requirement to post data regarding their processing of transmission service requests. Although RTOs and ISOs have no generation affiliates, TDU Systems argue that requiring RTOs and ISOs to post information as to the number of requests made and rejected would make the acquisition of transmission services more transparent, serve as a signal for potential congestion problems on the system that should be studied through the planning process, and alert market participants to the emergence of market power in local submarkets.

139. Constellation requests that the Commission clarify that the requirement to post underlying load forecast assumptions includes a complete list of modeling assumptions, protocols and automation modifications, including what the adjustments are and how they are applied. Constellation states that it requested that such information be required in its NOPR comments, but that it is unclear whether the requirement in Order No. 890 is broad enough to reflect that request.

140. E.ON LSE requests that the Commission grant rehearing to permit utilities to decline to publicly post information regarding actual load and forecasts where such information is commercially sensitive or where customer-specific information is deemed confidential by the affected customer. E.ON LSE requests that such commercially sensitive information instead be posted four weeks after the time period that the data covers. E.ON LSE contends that disclosure of customer-specific load forecasts could have adverse competitive effects, such as a daily forecast signaling to sellers that a utility is in substantial need for additional energy during the upcoming day's operations. E.ON LSE contends that the goal of transparency is sufficiently met even with a slight delay in posting commercially sensitive forecasts and load data.

Commission Determination

141. In Order No. 890, the Commission required transmission providers to post on OASIS metrics regarding transmission service requests. The Commission did not distinguish between types of requests for transmission service. Transmission providers therefore should include in their metrics any type of request for service, including transmission service requests by affiliated merchant or trading entities as well as requests by the transmission provider's merchant function to designate or undesignate network resources or to procure secondary network service to serve native load. We revise our regulations to make this clear.

142. In response to TDU Systems, we clarify that Order No. 890 did not exempt RTOs and ISOs from the requirement to post metrics related to the provision of transmission service. While the affiliate posting requirements do not apply to RTOs and ISOs,[58] the requirement to post metrics regarding all transmission service requests remains.[59] We agree with TDU Systems that requiring RTOs and ISOs to post non-affiliate transmission service request metrics improves the transparency of transmission service request processing by those transmission providers.

143. In response to Constellation, we clarify that underlying load forecast assumptions should include economic and weather-related assumptions. We revise our regulations to clearly state the obligation to post both actual daily peak load and load forecast data, as required in Order No. 890.[60] We decline to adopt E.ON LSE's request to delay release of load data required to be posted in Order No. 890. Posting load forecast and actual load data on a control area and LSE level provides necessary transparency to transmission customers and does not, in our view, raise serious competitive implications.[61] If there is customer-specific information deemed confidential by the affected customer that impedes the ability of the transmission provider to post this data, we will consider requests for exemption from the posting requirement on a case-by-case base.

[58] *See* Order No. 890 at P 414.

[59] *See* 18 CFR 37.6(i)(1) and (2).

[60] *See* Order No. 890 at P 416.

[61] *See id.* at P 417.

(5) Requests for Additional Transparency

Requests for Rehearing and Clarification

144. Constellation repeats a request from its NOPR comments to require transmission providers to post certain additional modeling data, modeling support information, and model benchmarking and forecasting data/TSR study audit data (identified in an attachment to its request for rehearing). Constellation argues that, since Order No. 890 requires transmission providers to calculate much of this additional information, the Commission should require that it be posted as well. Constellation contends that these postings would allow transmission customers and the Commission to assess the likely availability of transmission capacity, verify or challenge the conclusions reached by the transmission provider on a specific transmission request, and identify constraints and congestion, as well as physical or financial measures that could be taken to optimize the use of transmission system.

145. EPSA asks the Commission to clarify that the standards developed during the NAESB process should require transmission providers to post essential details of ETCs that affect current customers' access to transmission capacity, including duration and volume, priority rights, redispatch and scheduling rights, and any other rights that affect others' use of the grid. As part of these postings, EPSA suggests that transmission providers be required to include information concerning transmission arrangements that are not provided under the OATT, *e.g.*, pre-OATT transmission arrangements. EPSA argues that non-OATT transmission arrangements often include terms that are inconsistent with OATT terms and which can impact OATT customers' access to the grid. Unless transmission providers are required to post ETC-related information, EPSA contends that there will be no way for market participants to determine whether the transmission provider has appropriately modeled ETC set-asides.

146. Powerex makes a similar request, reiterating a NOPR proposal that the Commission require transmission providers to post those provisions of pre-Order No. 888 contracts that affect current customers' access to transmission capacity, including duration and volume, priority rights, redispatch and scheduling rights, and any other rights that affect transmission access. Powerex further requests that the Commission prohibit the continuation

of grandfathered contracts unless the parties can point to a provision within the existing contract that contains explicit and guaranteed rights to extend or renew the contract term and reaffirm that pre-Order No. 888 contracts cannot be altered upon their expiration. Powerex complains that the Commission did not address these proposals in Order No. 890 and that no commenting party put forward credible evidence to rebut the information Powerex presented the Commission in its NOPR comments.

147. TDU Systems argue that transmission providers should be required to provide customers with access to modeling software used to calculate ATC values. TDU Systems state that Commission staff expressed concern at the Technical Conference held on October 12, 2006, in this docket that customers could find it difficult to sort through and use the large volume of data the Commission proposed to be posted by the transmission provider. TDU Systems argue that providing access to the modeling software used by the transmission provider to calculate ATC would resolve many of these concerns and better enable transmission customers to replicate and verify transmission provider ATC calculations, avoiding the potential for protracted litigation over the ATC results. TDU Systems contend that any proprietary or licensing concerns of the transmission provider or its vendors could be addressed through reasonable charges for use of the software and/or appropriate confidentiality agreements.

Commission Determination

148. In Order No. 890, the Commission required transmission providers to make available, upon request, all data used to calculate ATC, TTC, CBM and TRM for any constrained posted path.[62] We believe that this adequately addresses Constellation's request for access to modeling data used by the transmission provider. Specifically, we expect transmission providers to make available, upon request and subject to appropriate confidentiality protections and CEII requirements, the following modeling data: (1) Load flow base cases and generation dispatch methodology; (2) contingency, subsystem, monitoring, change files and accompanying auxiliary files; (3) transient and dynamic stability simulation data and reports on flowgates which are not thermally limited; (4) list of transactions used to update the base case for transmission service request study; (5) special protection systems and operating guides, and specific description as to how they are modeled; (6) model configuration settings; (7) dates and capacities of new and retiring generation; (8) new and retired generation included in the model for future years; (9) production cost models (including assumptions, settings, study results, input data, *etc.*), subject to reasonable and applicable generator confidentiality limitations; (10) searchable transmission maps, including PowerWorld or PSSE diagrams; (11) OASIS names to Common Names table and PTI bus numbers; and, (12) flowgate and interface limits including limit category (thermal, steady state or transient, voltage or angular). We decline, however, to require the transmission provider to post this information on OASIS, as Constellation suggests. We conclude that making this information available on request provides sufficient transparency for customers without unduly burdening the transmission provider.

149. With regard to the modeling support information sought by Constellation, we believe much of this information should already be stated in each transmission provider's Attachment C. In Order No. 890, the Commission required each transmission provider to set forth in the Attachment C to its OATT the ATC calculation methodology used by the transmission provider.[63] To the extent necessary, we clarify that the step-by-step modeling study methodology and criteria for adding or eliminating flowgates (permanent and temporary) is part of the ATC methodology that must be stated in the transmission provider's Attachment C. We direct any transmission provider that has failed to include this information in its Attachment C to include that information as part of the compliance filing directed in section II.C. If the transmission provider has already satisfied this obligation in a previous compliance filing, it should refer to that filing instead.

150. We deny as premature Constellation's request to require OASIS postings of additional model benchmarking and forecasting data/TSR study audit data. Such information would be utilized in the process of updating and benchmarking models to actual events, which is the subject of ongoing efforts to modify relevant reliability standards from the MOD and facilities design, connections and maintenance (FAC) groups.

151. We decline to impose additional posting requirements regarding ETC uses, as requested by EPSA and Powerex. In Order No. 890, the Commission required transmission providers to make available all data used to calculate ATC for constrained paths and any system planning studies or specific network impact studies performed for customers.[64] This would include information regarding ETC uses, including grandfathered agreements, that affect ATC calculations or study results. EPSA and Powerex fail to demonstrate that it is necessary to require the posting of additional information regarding ETC uses to verify the accuracy of the transmission provider's ATC calculations. We note in response to Powerex that, if any new service taken upon expiration of a pre-Order No. 888 contract, the terms and conditions of the transmission provider's OATT would apply.[65]

152. We deny TDU Systems' request to require transmission providers to grant customers access to proprietary modeling software used to calculate ATC values. The Commission believes at this time that the requirements of Order No. 890 are sufficient to achieve the Commission's transparency goals without further requiring the disclosure of proprietary software.

B. Coordinated, Open, and Transparent Planning

1. The Need for Reform

153. In Order No. 890, the Commission required transmission providers to participate in a coordinated, open, and transparent planning process on both a local and regional level. Transmission providers, including RTOs and ISOs, were directed to submit a compliance filing describing their proposals for a coordinated and regional planning process that comply with the planning principles and other requirements of Order No. 890. The transmission planning process must be documented as an attachment to the transmission provider's OATT.

154. The Commission determined that planning-related reforms were necessary in order to limit opportunities for undue discrimination and to ensure that comparable transmission service is provided by all public utility transmission providers. The Commission stated that it did not intend to reopen prior approvals regarding planning processes adopted by RTOs and ISOs and, instead, sought to ensure that such planning processes are

[62] *See id.* at P 348.

[63] *See id.* at P 323.

[64] *See id.* at P 348.

[65] *See* Order No. 888 at 31,655.

consistent with or superior to the requirements of Order No. 890. In order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process. The Commission therefore directed RTOs and ISOs to indicate in their compliance filings how participating transmission owners within their footprint will comply with the planning requirements of Order No. 890.

155. The Commission also noted that the planning obligations imposed in Order No. 890 did not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers. Through the principles adopted by the Commission, a process was established through which transmission providers will coordinate with customers, neighboring transmission providers, affected state commissions, and other stakeholders in order to ensure that transmission plans are not developed in an unduly discriminatory manner.

Requests for Rehearing and Clarification

156. E.ON U.S challenges the Commission's authority to adopt transmission planning rules beyond the implementation of service reservations or requests by customers. E.ON U.S. argues that the Commission's reliance on new section 217(b)(4) of the FPA is misplaced because that provision does not enlarge the Commission's authority and, in any event, Order No. 890 goes beyond assuring that LSEs have adequate transmission service. E.ON U.S. contends that characterizing transmission planning as a practice affecting rates would require an expansion of the Commission's jurisdiction over the underlying rate, which it argues does not exist.

157. Southern states that it supports the bulk of the coordinated planning provisions of Order No. 890, but nonetheless argues that reform is not needed to ensure that transmission planning is performed on a non-discriminatory basis. Southern states that it has invested billions of dollars in transmission over the last decade and expects to continue the trend of considerable investment through the foreseeable future. Southern also contends that it and other vertically-integrated utilities have obligations to procure generation through nondiscriminatory requests for proposals and that contracts awarded to any non-affiliated generator are already incorporated into the planning process as designated resources. Southern therefore contends that it does not have a disincentive to impede the ability of lower cost generation to access its control area. Southern suggests that any failure to upgrade interfaces is due to the lack of long-term firm service commitments to justify the upgrade, not a desire to keep lower-cost power from accessing the transmission provider's control area.

158. NYISO challenges the Commission's reform of previously-approved RTO and ISO planning processes, arguing that the Commission cannot require changes to the NYISO planning process without first making a finding that it is no longer just and reasonable. NYISO contends that no such finding was made in Order No. 890, nor did the Commission identify discrimination in areas with centralized markets, such as NYISO.

159. NRECA, Old Dominion, and TDU Systems ask the Commission to clarify that those RTOs and ISOs and other public utility transmission providers able to demonstrate that their planning processes are consistent with or superior to the requirements of Order No. 890 must nevertheless still file their planning process as part of their OATTs. These petitioners contend that requiring an RTO or an ISO to include the details of its planning process in its OATT, rather than its operating agreements, business manuals or Web site postings, will enable the Commission to monitor compliance with the reformed planning principles of Order No. 890 and provide needed transparency for customers. Entergy requests clarification that a transmission provider that has transferred authority over planning activities to an independent transmission coordinator may make the same compliance filings as an RTO/ISO, demonstrating that its existing planning process is consistent with or superior to the Order No. 890 requirements.

160. Old Dominion asks the Commission to clarify that the list of requirements in paragraph 602 of Order No. 890 (regarding the level of detail to be included in the OATT) is not exclusive and that, instead, every transmission provider must include the entirety of its planning process in its Attachment K with sufficient detail for stakeholders to understand that process. TDU Systems seek further clarification that transmission providers that have not turned over operational control of their facilities to an RTO or ISO must comply with the Attachment K filing obligations even if their facilities are governed by non-OATT arrangements, such as facilities agreements.

161. Several petitioners ask the Commission to clarify whether individual transmission-owning members within an RTO/ISO must comply with the planning-related posting and filing requirements of Order No. 890.[66] New York Transmission Owners argue that, where there is an existing compliant regional planning process conducted by an RTO or ISO, participation in the planning process by a transmission owner is sufficient to satisfy the requirements of Order No. 890. Old Dominion and TDU Systems, however, seek confirmation that each of the nine planning principles adopted by the Commission apply equally to transmission owners that are members of an RTO, otherwise the RTO's planning process will be insufficient to satisfy the requirements of Order No. 890. TDU Systems argue that RTO and ISO tariff filings must provide detail on how the RTO will ensure transmission owner compliance with planning requirements and that reliance on statements of commitment to comply would be insufficient. Old Dominion contends that all filing and posting obligations should rest with the RTO or ISO and not their transmission-owning members. EEI suggests that the processes for incorporating the planning processes of transmission owning members of RTOs and ISOs should be addressed by each RTO and ISO.

162. National Grid objects to any obligation to allow stakeholders an opportunity to preview the internal planning deliberations of transmission-owning RTO/ISO members prior to presentation of plans to the RTO or ISO. National Grid argues that this would give special interest stakeholders two opportunities to oppose specific projects, once at the local level without the full participation of the region and again at the regional level, and undermine the ability of the regional process to resolve conflicts between competing proposals. National Grid contends that it would be unfair to require transmission owners to open up their internal deliberations in advance of the regional planning process while allowing other stakeholders to deliberate in private their own strategies for the regional planning process. National Grid asks the Commission to clarify that the regional planning process is the appropriate forum in which stakeholders can examine each other's upgrade proposals. National Grid argues that the adoption of separate local planning processes is not necessary to remedy undue discrimination and is unnecessary given

[66] *See, e.g.,* EEI, National Grid, New York Transmission Owners, Old Dominion, and TDU Systems.

that stakeholders in the ISO–NE regional planning process have an opportunity to comment on all aspects of the transmission plan, even those developed by the underlying transmission owners.

163. Several petitioners challenge the Commission's decision in Order No. 890 not to mandate the construction of facilities identified in a transmission plan. TAPS argues that the Commission's finding that discrimination exists in expansion decisions compels obligating transmission providers to build needed facilities to accommodate uses identified in the planning process or explain why they cannot do so. TAPS contends that, under Order No. 890, a transmission provider can choose to build only the planned upgrades that benefit its native load, leaving a weak and uneven grid that prevents embedded TDUs from accessing economic alternatives.

164. TAPS asks that the following measures be adopted to protect the interest of customers potentially harmed by failing to obligate the transmission provider to construct facilities identified in the transmission plan. First, TAPS suggests that transmission providers be required to accept any request for transmission to a network customer load, if necessary by redispatch shared on a load-ratio basis, if the request would have been accepted if the transmission provider's own load had been designated the sink. Second, TAPS asks the Commission to require transmission providers to accept a network customer's timely designated network resource so long as the designation is consistent with the regional transmission plan and the long-term projections and planning information provided by the customer pursuant to OATT § 31.6 and in the planning process, supporting the network resource designation through redispatch if necessary, with costs shared on a load-ratio basis. Third, TAPS suggests that transmission providers be required to offer embedded cost sales to transmission-dependent utilities if the provider's failure to plan and construct on a comparable basis has left those embedded utilities trapped without reasonable access to competitive alternatives. Finally, TAPS asks the Commission to make clear that its ''toolbox'' to address egregious failures to plan and construct a robust grid that meets the needs of network customers includes the exercise of jurisdiction over the transmission component of bundled retail sales of a particular utility to remedy undue discrimination.[67]

165. TAPS argues that these measures would provide transmission providers with the right financial incentives to construct facilities identified in the transmission plan. If the transmission provider fails to build and there is insufficient capacity to accommodate planned uses, TAPS argues it is appropriate for the transmission provider to share the cost of providing alternative service. TAPS argues that this would also mitigate the Commission's concern that imposing an obligation to build would conflict with the need for transmission plans to change over time.

166. TAPS also suggests that the Commission monitor the transmission provider's actions by requiring any denial of service to a network customer be reported to the Commission so that the transmission provider can demonstrate to enforcement staff that the transmission provider has adequately planned for its customers and made diligent efforts to build planned upgrades. TAPS also argues that transmission providers should be required to demonstrate that they are making good faith efforts to obtain any necessary state and local siting approvals and to acquire any property rights necessary to construct planned facilities in order to show that they are not selecting projects for construction that favor their own uses over the uses of their network customers.

167. TDU Systems agree that better planning will not remedy or mitigate undue discrimination without an enforceable obligation to actually construct upgrades needed to ensure reliable and economic service to LSEs. TDU Systems argue that an obligation to build would be consistent with other reforms adopted in Order No. 890, such as extending the minimum term of contracts eligible for rollover rights and eliminating the price cap on reassignments of capacity, by ensuring that adequate capacity exists to accommodate transmission service requests. They contend that the failure to mandate expansion of the grid is particularly egregious in situations when zero ATC values are posted on a recurring or lengthy basis, which they argue should trigger a rebuttable presumption that congestion exists on the transmission system and that upgrades are needed. TDU Systems contend that failing to require transmission providers to expand their systems in these and other situations is inconsistent with the requirement of section 217(b)(4) of the FPA for the Commission to exercise its authority to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of LSEs.

168. TDU Systems suggest that the Commission strengthen and aggressively enforce the existing construction obligations in the *pro forma* OATT and subject transmission providers that fail to implement a transmission plan in good faith to sanctions. TDU Systems argue that section 28.2 of the *pro forma* OATT should be amended to require a transmission provider to do more than endeavor to construct new facilities needed to meet network customer load or, in the alternative, the Commission should indicate that it will aggressively enforce the existing obligation to build. They request that the Commission adopt a clear policy of sanctions for cases in which a transmission provider is found to have failed to proceed in good faith and with due diligence in implementing the planning process. TDU Systems ask the Commission to clarify in particular that it will consider revocation of market-based rate authority for bad faith in implementing the transmission planning and expansion requirements under Order No. 890.

169. NRECA also urges the Commission to reiterate and enforce the existing obligations to build in order to meet its service obligations to network and long-term point-to-point customers under the *pro forma* OATT.[68] NRECA argues that the obligation to expand capacity should be viewed as part and parcel of the transmission provider's obligation to plan for these customers and that statements to the contrary in Order No. 890 should be clarified. NRECA argues that leaving the transmission provider with the discretion not to build facilities identified in the transmission plan would allow it to discriminate in favor of its native load customers to the detriment of network and long-term point-to-point customers.

170. Washington IOUs request clarification that the planning requirements of Order No. 890 do not supersede the planning and coordination activities undertaken by a transmission provider under its network operating agreements. Washington IOUs state that transmission providers providing network service currently engage in local planning and coordination activities with network customers to ensure their needs are met and that such activities should not be

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

[68] *Citing pro forma* OATT sections 13.5, 15.4 and 28.2.

superseded by the planning-related reforms of Order No. 890.

Commission Determination

171. The Commission affirms the decision in Order No. 890 to amend the *pro forma* OATT to require coordinated, open and transparent transmission planning on both a local and regional level. Although the Commission encouraged utilities to engage in joint planning in Order No. 888–A, it placed no affirmative obligation on transmission providers to coordinate with their customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans, nor were transmission providers required to coordinate planning activities with other transmission providers in their region. This lack of clear criteria regarding planning obligations has created opportunities for undue discrimination by transmission monopolists with an incentive to deny transmission or offer transmission on an inferior basis.

172. Petitioners generally do not challenge the Commission's conclusion that the lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning and, instead, raise more narrow arguments regarding particular aspects of the planning reforms. E.ON U.S. argues that the Commission must limit the scope of the planning requirements to implementation of service requests. We disagree. The Commission has a statutory obligation under sections 205 and 206 of the FPA to ensure that each public utility's rates, charges, classifications, and services are just and reasonable and not unduly discriminatory. The Commission has exercised jurisdiction over planning-related proposals submitted by individual transmission providers in the past, rejecting arguments regarding a lack of jurisdiction.[69] Transmission planning activities are within our jurisdiction and, therefore, we have a duty under FPA section 206 to remedy undue discrimination in this area and a further obligation under FPA section 217 to act in a way that facilitates the planning and expansion of facilities to meet the reasonable needs of LSEs.

173. The fact that transmission providers, such as Southern, have undertaken some transmission investment in recent years does not mean that planning reform is not needed. Southern does not challenge the fundamental conclusion that it is in the economic self-interest of transmission monopolists to discriminate in the provision of service and, in turn, in planning-related activities. The ability of generators to participate in requests for proposals for *generation* service does not adequately respond to the need for a coordinated, open, and transparent *transmission* planning process that considers the needs of all customers as well as the transmission provider itself. The planning process adopted in Order No. 890 is designed to enhance the ability of all customers to make long-term firm service commitments by allowing them to participate in the transmission provider's planning activities.

174. The Commission also based its planning-related reforms on the need to ensure comparable transmission service by all transmission providers, including RTOs and ISOs. We therefore disagree with NYISO that the Commission failed to justify application of the Attachment K filing obligations to RTOs and ISOs. The Commission was not required to find each and every tariff unjust and unreasonable to adopt this rulemaking, and, instead, had the discretion to adopt principles of generic applicability to govern all transmission tariffs. Indeed, we made clear, and reiterate here, that RTOs and ISOs can continue to rely on their existing planning processes if those processes meet the requirements of Order No. 890. As the Commission explained, it is not our intention to reopen prior approvals simply for the sake of doing so, but rather to ensure that those previously approved planning processes fulfill the obligations imposed on all transmission providers in Order No. 890.[70]

175. We therefore affirm the decision to require all transmission providers to comply with the planning-related reforms adopted in Order No. 890, including RTOs and ISOs. We agree with Old Dominion that the filing and posting requirements stated in Order No. 890 apply only to the transmission provider, *e.g.*, the RTO or ISO, and not the transmission-owning RTO/ISO members without an OATT.[71] Each RTO and ISO may fulfill its obligations under Order No. 890 by delegating certain actions to, or otherwise relying on, their transmission-owning members, provided that the rights and responsibilities of all parties are clearly stated in the transmission provider's OATT. In the end, however, it is each RTO's and ISO's responsibility to demonstrate compliance with each of the nine planning principles adopted in Order No. 890 since it is the entity with the Attachment K on file.

176. We clarify in response to National Grid that an RTO or ISO would not be able to satisfy the requirements of Order No. 890 if the plans developed by its transmission-owning members and relied upon by the RTO/ISO did not also satisfy those requirements. A fundamental assumption underlying National Grid's argument is that issues addressed in a local planning proposal should be final prior to its introduction at the regional level. Yet such finality could exclude customers from the development of aspects of what eventually becomes the regional plan implemented by the RTO or ISO. As the Commission explained in Order No. 890, local planning issues may be critically important to some transmission customers, such as those embedded within the service areas of individual transmission owners.[72] While we leave the mechanics of incorporating the planning processes of transmission owning members to each RTO and ISO, as EEI suggests, it would not be appropriate to entirely exclude such processes as proposed by National Grid.

177. To the extent necessary, we clarify in response to NRECA, Old Dominion and TDU Systems that every transmission provider, including RTOs and ISOs, must submit a compliance filing stating its transmission planning process in an attachment to its OATT. This tariff language must satisfy all of the requirements of Order No. 890 with sufficient detail for stakeholders to understand the planning process implemented by the transmission provider. To the extent the transmission provider previously received Commission approval to delegate planning responsibilities to an independent transmission coordinator, the transmission provider may demonstrate in its compliance filing that its planning process is consistent with or superior to the Order No. 890 planning requirements, similar to the RTO and ISO compliance filings.

178. The Commission declines to expand the *pro forma* OATT to place additional obligations on the

[69] *See New York Independent System Operator, Inc.*, 109 FERC ¶ 61,372 at P 18 (2004); *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 at P 78 (2004).

[70] *See* Order No. 890 at P 437.

[71] As the Commission noted in Order No. 890, transmission owning members of an RTO or ISO that continue to have OATTs on file under which they provide service over jurisdictional facilities not under control of the RTO or ISO would continue to have filing obligations under Order No. 890, like any other transmission provider. *See id.* at P 440, n.247. This would apply equally to a transmission provider that has retained operational control of facilities governed by other non-OATT arrangements.

[72] *See id.* at P 440.

transmission provider to construct facilities identified in its transmission plan. As the Commission explained in Order No. 890, there may be reasons a transmission provider declines to undertake a particular project given the complexity of the transmission grid and changing conditions of supply and demand.[73] Our focus is therefore on the process leading to the transmission plan and not the construction of specific facilities. This does not, as some petitioners argue, undermine the construction-related obligations that exist under sections 13.5, 15.4 and 28.2 of the *pro forma* OATT. The planning-related reforms adopted in Order No. 890 are intended to support, not replace, those requirements by establishing a process to govern all planning-related decisions.

179. We therefore believe adequate protections are in place to ensure that transmission providers do not unduly discriminate in the selection of which facilities they choose to construct to the detriment of their customers. If a particular customer believes that its transmission provider has in fact not complied with its OATT obligations, the customer should bring the matter to the Commission's attention, such as by filing a complaint. Indeed, the planning-related reforms adopted in Order No. 890 will facilitate tariff compliance by opening up the transmission provider's decisional process, providing much needed transparency in the area of transmission planning.

180. We deny as unnecessary TAPS' request to impose additional accountability mechanisms or require other demonstrations regarding a transmission provider's construction decisions or to generically address the appropriateness of sanctions, including revocation of market-based rate authority, for non-compliance with tariff obligations. We will likewise deny requests to revise the construction-related obligations of the *pro forma* OATT. The Commission will remain actively involved in the review and implementation of the transmission planning processes required in Order No. 890, during and beyond the initial compliance phase, to ensure that the potential for undue discrimination in planning activities is adequately addressed. Further, we expect transmission customers to advise the Commission if transmission providers do not adhere to the terms of the tariff provisions we ultimately approve. In the absence of specific evidence that a transmission provider has failed to satisfy its tariff obligations, either under sections 13.5, 15.4 or 28.2 of the *pro forma* OATT or its Attachment K planning process, we believe it unnecessary to adopt the additional measures proposed by TAPS. In the case of tariff non-compliance, the Commission will consider these and any other remedies that may be appropriate on a case-by-case basis in the context of the specific facts presented.

2. Planning Principles

181. The Commission identified nine planning principles in Order No. 890 that must be satisfied for a transmission provider's planning process to be considered compliant with that order. These nine planning principles are:

(1) *Coordination*—the process for consulting with transmission customers and neighboring transmission providers;

(2) *Openness*—planning meetings must be open to all affected parties;

(3) *Transparency*—access must be provided to the methodology, criteria, and processes used to develop transmission plans;

(4) *Information Exchange*—the obligations of and methods for customers to submit data to transmission providers must be described;

(5) *Comparability*—transmission plans must meet the specific service requests of transmission customers and otherwise treat similarly-situated customers (*e.g.*, network and retail native load) comparably in transmission system planning;

(6) *Dispute Resolution*—an alternative dispute resolution process to address both procedural and substantive planning issues must be included;

(7) *Regional Participation*—there must be a process for coordinating with interconnected systems;

(8) *Economic Planning Studies*—study procedures must be provided for economic upgrades to address congestion or the integration of new resources, both locally and regionally; and

(9) *Cost Allocation*—a process must be included for allocating costs of new facilities that do not fit under existing rate structures, such as regional projects.

Petitioners have requested rehearing and clarification regarding certain of these principles, which we address in turn.

a. Coordination

182. In order to satisfy the coordination principle, transmission providers must provide stakeholders the opportunity to participate fully in the planning process. The purpose of the coordination requirement is to eliminate the potential for undue discrimination in planning by opening appropriate lines of communication between transmission providers, their transmission-providing neighbors, affected state authorities, customers, and other stakeholders. The planning process must provide for the timely and meaningful input and participation of customers regarding the development of transmission plans, allowing customers to participate in the early stages of development.

Requests for Rehearing and Clarification

183. EPSA and TDU Systems argue that, under Order No. 890, transmission providers inappropriately retain veto rights over the decision as to which upgrade projects to include in transmission plans. These petitioners acknowledge that the transmission provider has the ultimate obligation to comply with its tariff, but argue that those tariff obligations be fulfilled in a way that allows for full and equal participation of customers. EPSA argues that transmission providers should be obligated to consider consensus positions, to present to the Commission or its designee minority opinions that have been excluded, and to explain why consensus proposals that have been disregarded will not be converted into actual plans to expand or reduce constraints on the system. TDU Systems request that transmission providers be required to post on their Web sites a record of the transmission planning decisions that reflect the views and votes of all participants to that process. TDU Systems argue that this would enable the Commission to determine whether the plan reflects consensus among stakeholders and the needs of customers, as opposed to the unilateral determinations of the transmission providers. NRECA asks the Commission to clarify that LSEs in particular have the opportunity to be an integral and equal part of the regional planning process from the beginning of the process to its end, including implementation of the regional participation principle.

184. NRECA argues that comparability requires that LSEs have equal weight in decision-making. Otherwise, NRECA contends that transmission providers will continue to have the opportunity and right to discriminate. NRECA expresses concern that transmission providers will be able to develop the basic criteria, assumptions, and data that underlie transmission plans on their own and merely present the results to customers after the fact. NRECA asks the Commission to clarify that public utility transmission providers may not arbitrarily, deliberately, or

[73] *See id.* at P 594.

discriminatorily disregard the input of LSE customers at any stage in the development and drafting of the transmission plan and modify the *pro forma* Attachment K to reflect that LSEs will be an integral part of the planning process.

185. With regard to small LSE customers, NRECA asks the Commission to clarify that the new requirement that transmission providers develop and implement joint planning processes does not leave customers that lack the resources to fully participate in the planning process in a worse position than they were in under Order No. 888. NRECA states that, under Order No. 888, transmission providers were required to plan and expand their systems to meet the needs of all network customers and long-term point-to-point customers. NRECA contends that the new joint planning requirement could be read to allow transmission providers to refuse to consider these customers' needs if they are unable to participate fully in the transmission planning process. NRECA suggests that participation in the planning process be an opportunity for load-serving customers, not an obligation, and that transmission providers be required to plan for those that are unable to fully participate.

186. Constellation requests that the Commission clarify that it will closely monitor the planning process to ensure that reforms are implemented in a meaningful way and that customers have the ability to truly participate in the process. Williams requests that the planning-related requirements of Order No. 890 be augmented to require a written record of stakeholder input, in order to guarantee informed consideration and debate of non-transmission provider proposals.

187. EEI seeks clarification that transmission providers may adopt restrictions on the disclosure of CEII in the context of transmission planning. EEI argues that login requirements and nondisclosure agreements may not provide sufficient protection for CEII. EEI suggests that transmission providers be allowed to adopt the Critical Infrastructure Protection (CIP) reliability standards for the disclosure of CEII that the Commission adopts in Docket No. RM06–22–000, *Mandatory Reliability Standards for Critical Infrastructure Protection.*

Commission Determination

188. The Commission affirms the decision in Order No. 890 not to require the development of transmission plans on a co-equal basis with customers. Transmission planning is the tariff obligation of the transmission provider, and the *pro forma* OATT planning process adopted in Order No. 890 is the means to see that it is carried out in a coordinated, open, and transparent manner. It would not be appropriate to allow customers and others that do not bear the responsibility for tariff compliance to have co-equal control over the planning process. We reiterate, however, that the planning process must provide for the timely and meaningful input and participation of all interested customers and other stakeholders in the development of transmission plans. Customers and other stakeholders therefore must have the opportunity to participate at the early stages of the development of the transmission plan, rather than merely given an opportunity to comment on transmission plans that were developed in the first instance without their input.

189. We disagree that the additional processes proposed by EPSA, TDU Systems, and Williams are necessary at this time to ensure that transmission providers do not unduly discriminate in the performance of their planning responsibilities. Customers and other stakeholders have been given a meaningful opportunity to participate in the planning process and to voice their concerns, not a formal ''vote'' on the transmission plan. While we would not consider it reasonable for the transmission provider to act in an arbitrary fashion by simply ignoring the comments and concerns of interested parties, we do not believe it appropriate at this time to adopt additional procedural mechanisms to measure or track the views of those participants in the planning process. Should disputes arise, they should first be addressed through the dispute resolution process set forth in the transmission provider's Attachment K and then, if necessary, to the Commission's attention through a complaint or other appropriate procedural mechanism.

190. With regard to participation by small LSEs in planning activities, we reiterate that the planning process adopted in Order No. 890 is intended to supplement, not replace, the transmission provider's obligations under section 28.2 of the *pro forma* OATT to plan for the transmission needs of its network customers on a comparable basis and in accordance with Good Utility Practice, as well as the obligation to construct new facilities pursuant to sections 13.5 and 15.4 of the *pro forma* OATT to meet the service requests of its long-term point-to-point customers. Transmission providers are therefore required to craft a planning process that allows for a reasonable and meaningful opportunity for those that are interested and able to meet and otherwise interact with the transmission provider.[74] Notwithstanding a smaller LSE's inability to participate in the additional processes implemented in compliance with Order No. 890, the transmission provider still must fulfill its network service obligation to that customer.

191. In response to EEI, we clarify that, in addition to login requirements and nondisclosure agreements, transmission providers may adopt further restrictions on the distribution of CEII consistent with any CIP reliability standards that the Commission may adopt in Docket No. RM06–22–000.

b. Openness

192. In order to satisfy the openness principle, transmission planning meetings must be open to all affected parties including, but not limited to, all transmission and interconnection customers, state commissions and other stakeholders. The Commission recognized in Order No. 890 that it may be appropriate in certain circumstances, such as a particular meeting of a subregional group, to limit participation to a relevant subset of these entities. The Commission emphasized, however, that the overall development of the plan must remain open.

Requests for Rehearing and Clarification

193. TDU Systems argue that any condition under which a transmission planning meeting could be limited so as to exclude certain customers or stakeholders must be explicitly set forth in the transmission provider's Attachment K. Otherwise, TDU Systems contend the transmission provider will retain undue discretion over who is allowed to participate in meetings.

Commission Determination

194. The Commission agrees with TDU Systems that the circumstances under which participation in a planning meeting is limited should be clearly described in the transmission provider's Attachment K planning process. All affected parties must be able to understand how, and when, they are able to participate in planning activities.

c. Transparency

195. In order to satisfy the transparency principle, transmission providers must disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. The Commission concluded that this

[74] *See* Order No. 890 at P 453.

information should enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion. Among other things, the Commission required transmission providers to make available information regarding the status of upgrades identified in their transmission plans in addition to the underlying plans and related studies.

Requests for Rehearing and Clarification

196. TDU Systems ask the Commission to clarify that transmission providers, and transmission-owning members of an RTO or ISO, must provide customers and other stakeholders with base case and change case data. TDU Systems contend that this would be consistent with the Commission's goal of allowing stakeholders to replicate the results of planning studies and, in their view, would virtually eliminate disputes regarding whether planning has been conducted in an unduly discriminatory fashion.

197. TAPS questions whether the Standards of Conduct would trigger the full functional separation requirement for a non-public utility transmission provider participating in the planning process. TAPS contends that both transmission and generation functions of a non-public utility transmission provider could participate in planning activities, consistent with the Standards of Conduct, so long as all information used in transmission planning is made available to all participants. If the Commission disagrees, TAPS asks that new mechanisms be adopted to assure information is not abused, independent from the Standards of Conduct and existing Standards of Conduct waivers that do not inhibit the participation of non-public utility transmission providers in the planning process. TAPS suggests that any entity be allowed to participate in the regional planning process if it establishes procedures defining which employees/consultants may receive confidential transmission and planning information and prohibiting such employees/consultants from sharing that information with the entity's wholesale merchant personnel.

198. Old Dominion requests that the Commission adopt performance metrics governing transmission planning in addition to reports regarding the status of upgrades. Old Dominion suggests that the Commission specifically require transmission providers to report on the progress and construction of all upgrades and facilities in the transmission plan.

Commission Determination

199. In Order No. 890, the Commission required transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans.[75] To the extent necessary, we clarify in response to TDU Systems that this includes disclosure of transmission base case and change case data used by the transmission provider. These are basic assumptions necessary to adequately understand the results reached in a transmission plan.

200. With regard to management of non-public information by non-public utility transmission providers, we reiterate that the reciprocity obligation requires non-public utility transmission providers to abide by the Standards of Conduct or obtain waiver of them.[76] Although we recognize that compliance with the Standards of Conduct can impose costs on small entities, an open planning process cannot be fully successful if certain entities (whether jurisdictional or nonjurisdictional) can use planning-related information to obtain an undue advantage. The Commission therefore explained in Order No. 890 that it may be necessary to revisit waivers of the Standards of Conduct granted to certain non-public utility transmission providers in the past.[77] The Commission declined to alter such waivers on a generic basis in Order No. 890 and we affirm that decision here.

201. As TAPS notes, many of the concerns regarding management of non-public information shared in the planning process can be alleviated by simultaneous disclosure of that information to all participants. Moreover, the Standards of Conduct govern the relationship and exchange of information between transmission providers and their marketing or energy affiliates. Entities that do not own, operate or control transmission facilities, and who are not affiliated with transmission providers, are not subject to the Standards of Conduct. We believe establishment of new mechanisms to manage the sharing of non-public planning information by transmission providers subject to the Standards of Conduct would be premature and more appropriately addressed in any proceeding in which the revocation of a Standards of Conduct waiver is considered.

202. We also decline to adopt additional performance metrics governing transmission planning. The Commission required in Order No. 890 for transmission providers to make available information regarding the status of upgrades identified in their transmission plans.[78] Customers and other stakeholders that are interested in the implementation of the transmission plan will be able to monitor this information to gather information regarding the progress and construction of upgrades and facilities. The Commission does not believe further reporting requirements are necessary at this time to keep interested parties informed regarding the status of upgrades identified in a transmission plan.

d. Information Exchange

203. In order to satisfy the information exchange principle, transmission providers must develop guidelines and a schedule for the submittal of information in consultation with their network and point-to-point customers. The Commission stressed that information collected by transmission providers to provide transmission service to their native load customers must be transparent and equivalent information must be provided by transmission customers to ensure effective planning and comparability. Point-to-point customers were also required to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points.

Requests for Rehearing and Clarification

204. E.ON U.S. requests that the Commission clarify that all entities seeking comparable treatment for transmission planning purposes, including any non-public utilities, must share their cost information with the transmission provider, as needed for planning purposes. E.ON U.S. contends that it must have access to information regarding all of its customers' dispatch and transmission costs in order to implement joint planning as envisioned by Order No. 890. E.ON U.S. acknowledges that this information would need to be treated as competitively sensitive and shielded from the transmission provider's merchant function employees.

205. Duke seeks clarification that projections of a point-to-point customer's anticipated needs do not have to be included in the models

[75] *See id.* at P 471.

[76] *See* Order No. 888–A at 30,286.

[77] *See* Order No. 890 at P 474.

[78] *See id.* at P 472.

serving as the predicate of the transmission plan. Duke agrees that, while projected uses may be helpful in understanding the scope of the potential need for future upgrades, only reservations impose an obligation on the transmission provider.

Commission Determination

206. The Commission clarifies in response to E.ON U.S. that, within the context of transmission planning, customers should only be required to provide cost information for transmission and generation facilities as necessary for the transmission provider to perform economic planning studies requested by the customer. If stakeholders request that a particular congested area be studied, they must supply relevant data within their possession to enable the transmission provider to calculate the level of congestion costs that is occurring in the near future.[79] This may necessarily involve customers providing their cost information. As E.ON U.S. notes, transmission providers must maintain the confidentiality of this information, protecting it from distribution to employees of the merchant function and its affiliates. Transmission providers must clearly define in their Attachment K the information sharing obligations placed on customers in the context of economic planning.

207. We clarify in response to Duke that good faith projections of anticipated point-to-point uses of the transmission system are intended only to give the transmission provider additional data to consider in its planning activities. The Commission did not intend to suggest in Order No. 890 that such projections be treated as a proxy for actual reservations. Even though they are not the equivalent of reserved uses of the system, such projections could, for example, provide planners with likely scenarios for new investment.

e. Comparability

208. In order to satisfy the comparability principle, transmission providers must develop, after considering the data and comments supplied by customers and other stakeholders, a transmission system plan that (1) meets the specific service requests of its transmission customers and (2) otherwise treats similarly-situated customers (*e.g.*, network and retail native load) comparably in transmission system planning. The Commission also required that customer demand resources be considered on a comparable basis to the service provided by comparable generation resources where appropriate.

Requests for Rehearing and Clarification

209. E.ON U.S. argues that the comparability principle poses a dilemma for vertically-integrated utilities in that the utility must engage in least cost planning at the state level, but is required to engage in comparable planning at the federal level. E.ON U.S. questions whether comparability requires the transmission provider to include all customer-identified projects in its plan or whether the transmission provider must merely consult with customers regarding their projects. E.ON U.S. also objects to treating a non-public utility customer comparably to its own native load in instances when the non-public utility customer fails to do the same in its own transmission planning activities. E.ON U.S. requests that the Commission clarify that public utilities are not required to include non-public utilities in transmission planning to the extent a non-public utility has not adopted the transmission planning principles of the *pro forma* OATT.

210. REPIO argue that planning processes must be clear to ensure that transmission providers fairly consider and implement the best alternatives among transmission, generation, and demand response options. To that end, REPIO ask the Commission to make explicit the requirement that all resource options be given technology neutral treatment.

211. Areva, however, argues that transmission providers must be required to do more than simply include demand resources in the planning process, arguing that the Commission failed to adequately encourage the use of alternative technologies as required by section 1223 of EPAct 2005. Areva contends that the Commission erred in failing to provide new opportunities for advanced technologies in the energy markets, particularly demand response resources. Areva argues it is inadequate to merely allow participation of comparable demand-side resources and, instead, the Commission must take the steps necessary to promote integration of advanced technologies in the planning process, including the assessment of penalties for failure to include such technologies in transmission plans and, ultimately, on the transmission grid. If the Commission declines to do so, Areva contends that the Commission at a minimum should require transmission providers to report their consideration of advanced technologies in their planning process, highlight uses of such technologies in their resulting transmission plan, or report to the Commission why such technologies were excluded from the resulting transmission plan.

212. TDU Systems, however, ask the Commission to confirm that demand resources can only substitute for truly comparable generation resources in the planning process. TDU Systems state that demand resources are, for example, non-dispatchable and can be reasonably substituted only for equivalent non-dispatchable blocks of energy. TDU Systems ask the Commission to establish criteria for determining whether demand resources are comparable to generation resources for purposes of consideration in the transmission plan or direct transmission providers to develop such criteria in their Attachment K proposals.

Commission Determination

213. Comparability requires that the interests of transmission providers and their similarly-situated customers be treated on a comparable basis in the transmission planning process.[80] We do not believe that this creates a conflict with least cost planning at the state level. Comparability simply requires that a transmission provider engage in comparable planning for its similarly-situated customers. The transmission provider retains discretion as to which solutions to pursue. Transmission providers are therefore not required to include all customer-identified projects in its plan, so long as similarly-situated customers are given comparable consideration.

214. With regard to non-public utility transmission providers, we reiterate our expectation of participation in the planning processes established pursuant to Order No. 890 consistent with their reciprocity obligations.[81] Reciprocity dictates that non-public utility transmission providers that take advantage of open access due to improved planning should be subject to the same requirements as jurisdictional providers. A non-public utility transmission provider with reciprocity obligations that declines to adopt a planning process that complies with Order No. 890 therefore may not be considered to be providing reciprocal transmission service and may be at risk of being denied open access transmission services by a public utility transmission provider. We will consider on a case-by-case basis how a transmission provider should treat for planning purposes a non-public utility

[79] *See id.* at P 550. The Commission also required the transmission provider's merchant function to provide any information necessary for economic planning studies (*e.g.*, redispatch cost information).

[80] *See id.* at P 494.

[81] *See id.* at P 441.

transmission provider that fails to implement a planning process that fulfills the requirements of Order No. 890.[82]

215. We disagree with Areva that the transmission planning process required in Order No. 890 is inconsistent with section 1223 of EPAct 2005.[83] The Commission made clear in Order No. 890 that advanced technologies and demand-side resources must be treated comparably where appropriate in the transmission planning process and, thus, the transmission provider's consideration of solutions should be technology neutral. We believe that the reforms adopted in Order No. 890 are sufficient to ensure comparable consideration of such technologies in transmission planning and, therefore, we decline to impose the type of special penalties proposed by Areva.

216. We disagree with TDU Systems that comparability requires that generation resources and demand resources be subject to the same operational parameters in every circumstance. Treating similarly-situated resources on a comparable basis does not necessarily mean that the resources are treated the same. As part of its Attachment K planning process, each transmission provider is required to identify how it will treat resources on a comparable basis and, therefore, should identify how it will determine comparability for purposes of transmission planning.

f. Dispute Resolution

217. In order to satisfy the dispute resolution principle, transmission providers must develop a dispute resolution process to manage disputes that arise from the Attachment K planning process. The Commission stated that the dispute resolution process must address both procedural and substantive planning issues, as the purpose for including a dispute resolution process is to provide a means for parties to resolve all disputes related to the planning process before turning to the Commission.

Requests for Rehearing and Clarification

218. TDU Systems ask the Commission to clarify that transmission providers must develop a dispute resolution process in collaboration with transmission customers and other stakeholders. TDU Systems argue that this clarification is necessary to assure that "the shape of the table" for dispute resolution is not fashioned to favor one side.

219. Duke asks the Commission to clarify whether alternative dispute resolution (ADR) will become a vehicle to challenge the transmission plan ultimately adopted by the transmission provider. Duke questions any intent by the Commission to exercise authority to approve or disapprove a transmission plan. Duke argues that ADR should not be used to substantively second guess a vertically-integrated transmission provider's plan. If ADR is intended to address substantive planning issues, Duke asks the Commission to clearly delineate the scope of those issues. Duke also asks the Commission to state the basis for any determination that ADR could be used to require changes to a transmission plan that would have the effect of fashioning binding obligations to build or not to build any particular facility in contravention of the transmission plan.

Commission Determination

220. As with any aspect of the transmission provider's Attachment K compliance filing, the Commission encourages stakeholder involvement in the development of an appropriate dispute resolution process to govern planning-related disputes. The Commission will carefully review each compliance filing to ensure that the proposed planning process is consistent with the principles and other requirements of Order No. 890. Any stakeholder that has concerns regarding the dispute resolution mechanism proposed by a transmission provider, or any other aspect of the compliance filing, may bring them to the Commission's attention on review of the proposal.

221. We disagree with Duke that the scope of this dispute resolution mechanism is limited to procedural issues. As the Commission explained in Order No. 890, the dispute resolution process should be available to address all disputes related to the planning process, both procedural and substantive.[84] This does not mean, as Duke implies, that any changes to the plan that may result from dispute resolution procedures become a binding obligation to build. In requiring a dispute resolution process for planning-related disputes, the Commission is not asserting any greater authority than it otherwise has to ensure that transmission providers comply with their tariff obligations to expand their systems to meet the needs of their customers. The dispute resolution process therefore does not change the rights or obligations otherwise established in the *pro forma* OATT. As we reiterate above, the Attachment K planning process does not place an affirmative obligation on the transmission provider to build upgrades identified in a plan. The tariff requirements regarding the construction of new facilities are covered in other portions of the *pro forma* OATT, as discussed above.

g. Regional Participation

222. In order to satisfy the regional participation principle, transmission providers must coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources. The Commission explained that the specific features of the regional planning effort should take account of and accommodate, where appropriate, existing institutions, as well as physical characteristics of the region and historical practices.

Requests for Rehearing and Clarification

223. TDU Systems ask the Commission to clarify that the regional participation principle requires both transmission providers and other stakeholders to be actively involved in regional planning activities. TDU Systems contend that some language in Order No. 890 could be read to limit regional coordination to transmission providers.[85]

224. National Grid asks the Commission to expand the regional participation principle to expressly require regions to adopt interregional planning processes subject to the same nine principles applicable to individual regions. National Grid argues that there will be little improvement in the area of interregional planning, and that disputes will continue to arise, in the absence of generic action by the Commission.

[82] As the Commission noted in Order No. 890, the Commission may exercise its authority under section 211A on a case-by-case basis if we find on the appropriate record that non-public utility transmission providers are not participating in the planning processes required therein. *See id.* at P 441.

[83] We note that, in addition to the reforms adopted in Order No. 890, the Commission is taking steps in other proceedings to encourage the deployment of advanced technologies as required by section 1223 of EPAct 2005. *See, e.g., Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (July 31, 2006), FERC Stats & Regs. ¶ 31,222 at P 302 (2006), *order on reh'g*, Order No. 679–A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007), *order on reh'g*, Order No. 679–B, 119 FERC ¶ 61,062 (2007).

[84] *See id.* at P 501.

[85] *Citing id.* at P 523.

225. EPSA suggests that Commission staff be designated to attend the development of all regional planning processes in non-RTO areas, in order to ensure adequate and timely oversight and accountability during the development stage, as well as to ensure that all stakeholders have a viable chance to participate in the development of their own regional planning processes.

Commission Determination

226. The Commission clarifies in response to TDU Systems that, while the obligation to engage in regional coordination is directed to transmission providers, participation in such processes is not limited to transmission providers. In Order No. 890, the Commission required transmission providers to develop a planning process that facilitates regional participation and required that process, in turn, to be open to all interested customers and stakeholders. In response to National Grid, we emphasize that effective regional planning should include coordination among regions. As the Commission explained in Order No. 890, the identification of relevant regions and sub-regions will depend on the integrated nature of the power grid and the particular reliability or resource issues affecting individual regions and sub-regions.[86] Each of these regions and sub-regions should coordinate as necessary to share data, information and assumptions to maintain reliability and allow customers to consider resource options that span the regions.

227. We decline EPSA's suggestion to direct Commission staff to attend the development of all regional planning processes in non-RTO areas. Commission staff has organized and attended a total of seven transmission planning technical conferences around the country, and engaged in numerous other meetings, phone calls and discussions, in order to assist transmission providers and customers in the development of planning processes that comply with the planning requirements of Order No. 890.[87] Transmission providers and stakeholders alike actively participated in these conferences. Any concerns regarding the inability of interested parties to participate in the development process can be raised on Commission review of the Attachment K compliance filings.

[86] *See id.* at P 627.

[87] The staff technical conferences were held on: June 4–7, 2007 in Little Rock, AR and October 1–2, 2007 in Atlanta, GA, covering the Southeast including Southwest Power Pool and its members; June 13, 2007 in Park City, UT, covering the Northwest and June 26, 2007 in Phoenix, AZ, covering the Southwest and California, as well as October 23–24, 2007 in Denver, CO, covering both of these regions; and June 28–29, 2007 in Pittsburgh, PA and October 15–16, 2007 in Boston, MA, covering the ISO New England, NYISO, PJM, MISO, and Mid-Continent Area Power Pool subregions.

h. Economic Planning Studies

228. In order to satisfy the economic planning studies principle, transmission providers must take into account both reliability and economic considerations in their Attachment K planning processes. The Commission stated that the purpose of this principle is to ensure that customers may request studies that evaluate potential upgrades and other investments that could reduce congestion or integrate new resources and loads on an aggregated or regional basis, and not to assign cost responsibility for any investments or otherwise determine whether they should be implemented.[88] The Commission determined that customers should be permitted to choose the studies that are of the greatest value to them, directing transmission providers to develop a means to allow the transmission provider and stakeholders to cluster or batch requests for economic planning studies so that the transmission provider may perform the studies in the most efficient manner. Customers must be given the right to request a defined number of high priority studies annually, the costs of which would be recovered as a part of the overall *pro forma* OATT cost of service.

Requests for Rehearing and Clarification

229. TDU Systems ask the Commission to clarify that the expansion of economic planning required in Order No. 890 to include integration of new resources and loads did not supplant the need to study both short-term and long-term congestion. TDU Systems further argue that any measure of congestion in the economic study process must be based on total gross congestion rather than hedgeable congestion, which they argue is unrealistic. TDU Systems state that in PJM, for example, congestion includes only that which cannot be hedged through financial instruments. TDU Systems contend that this ignores the significant costs of purchasing the financial instruments necessary to hedge the congestion and that gross congestion more accurately reflects what load pays for congestion.

[88] The Commission addressed the issue of cost allocation in a separate principle, discussed below.

230. TDU Systems also ask the Commission to clarify that each transmission provider must specify in its Attachment K the process for requesting and selecting economic planning studies and the number of high priority studies that will be paid for by the transmission provider. TDU Systems argue that the economic study process, including selection of which studies to perform, must be developed in collaboration with customers and other interested stakeholders. TDU Systems, as well as NRECA, suggest that the high priority studies only include those requested by non-affiliated customers so that the economic planning process is not usurped by the transmission provider and its affiliates.

231. AWEA asks the Commission to require transmission providers to engage in economic planning of upgrades to address the lumpiness of transmission investments. AWEA argues that the needs of native load groups, multiple generation projects, and load centers cannot be optimized unless they are combined in a single transmission plan. AWEA contends that comparability requires planning to provide capacity for OATT customers so that the cost of large, lumpy upgrades are not all assigned to single projects.

232. EEI requests clarification that the stakeholders' right to designate high priority studies applies to stakeholders as a group, not to individual stakeholders. EEI asserts that allowing individual stakeholders to designate specified numbers of studies would be impractical and inconsistent with the goal of an aggregated or regional approach to planning. Entergy asks the Commission to clarify that economic studies must be related to congestion issues affecting a stakeholder and not simply attempts to obtain competitive sensitive information about another party's resources and loads. Entergy suggests that a party requesting a study be required to explain the basis for its request and how the study relates to its own transmission service needs.

233. MISO, NYISO and National Grid ask the Commission to clarify that, within an RTO or ISO, requests for congestion studies must be made and approved through existing stakeholder processes. Otherwise, National Grid argues that studies may be tailor-made to the parochial interests of the requestor with limited subregional scope, which in its view would inhibit the regional planning process and tax RTO and ISO resources. NYISO requests further clarification that transmission-owning members of an RTO or ISO are not required to perform separate,

individual congestion studies at the request of customers.

234. Southern argues that the economic planning requirements of Order No. 890 should be based on the Commission's jurisdiction to ensure just and reasonable rates, since the information from such studies could facilitate customers' ability to optimize their future transmission service. Southern contends that neither Good Utility Practice nor comparability support adoption of the economic study requirements of Order No. 890. Southern states that its transmission function planners perform no congestion analysis and, instead, plan the system to satisfy reliability requirements and to meet the needs of firm transmission customers.

Commission Determination

235. The Commission affirms the decision in Order No. 890 to allow stakeholders the right to request a defined number of high priority studies annually to address congestion and/or the integration of new resources or loads.[89] The expansion of the economic planning principle in Order No. 890 did not supplant the need to study both short-term and long-term congestion, if requested by a stakeholder, as TDU Systems suggest. Similarly, the choice to study hedgeable or gross congestion is the choice of the requesting stakeholder or group of stakeholders. The intent of the economic planning principle is to allow stakeholders, and not the transmission provider, to identify the studies that are of the greatest value to them. This provides sufficient flexibility to address customer needs, including the study of large, lumpy transmission projects, as requested by AWEA.

236. We agree with petitioners that the transmission provider's Attachment K must clearly describe the process by which economic planning studies can be requested and how they will be prioritized.[90] We also agree that stakeholders as a group have the right to request the defined number of high priority studies to be paid for by the transmission provider.[91] As a result, transmission providers must develop a means to allow the transmission provider and customers to cluster or batch requests for economic planning studies so that the transmission provider may perform the studies in the most efficient manner. By limiting the economic planning principle to a defined number of high priority studies annually, the Commission did not intend to preclude stakeholders from requesting additional studies. To provide appropriate financial incentives, the stakeholder(s) requesting such additional studies would be responsible for paying the cost of such studies.[92]

237. We decline to generically limit the scope of economic planning studies as requested by Entergy. Studies may be requested to address congestion issues or the integration of new resources/loads. The limited number of high priority studies available should restrict the ability of stakeholders to use these studies for other purposes, since stakeholders and the transmission providers will be working together to determine which studies will be pursued. We also reject petitioners' suggestion that the requests made by a transmission provider's affiliates for economic planning studies should not count toward the defined number of high priority studies. The transmission provider's affiliates should be treated like any other stakeholder and, therefore, their requests for studies should be considered comparably, pursuant to the process outlined in the transmission provider's Attachment K.

238. We clarify in response to NYISO that it is the transmission provider's obligation to perform economic planning studies, just as it is the transmission provider's obligation to comply with other aspects of the planning process required in Order No. 890. As we explain above, RTOs and ISOs have flexibility in determining how to fulfill their planning-related obligations and may delegate certain responsibilities to their transmission-owning members or otherwise incorporate the processes of their members into the RTO/ISO planning process. To the extent an RTO or ISO delegates any of its responsibilities in the context of economic planning, it will be the obligation of the RTO or ISO to ensure ultimate compliance with the requirements of Order No. 890.

239. We disagree with Southern that the Commission may only require transmission providers to undertake economic planning studies pursuant to its authority to ensure just and reasonable rates. Consistent with our authority under FPA section 206, the Commission acted in Order No. 890 to limit the opportunities for undue discrimination in the area of transmission planning and to ensure that comparable service is provided by all public utility transmission providers. As the Commission explained in Order No. 890, a prudent vertically-integrated transmission provider will plan not only to maintain reliability, but also consider whether transmission upgrades or other investments can reduce the overall costs of serving native load.[93] To represent Good Utility Practice and provide comparable service, the transmission planning process under the *pro forma* OATT therefore must consider both reliability and economic considerations.

240. Southern states merely that its transmission planners do not perform congestion analyses in particular, not that they disregard economics in the planning of their system. Prudent vertically-integrated transmission providers take into consideration whether upgrades or other investments could allow them to meet the needs of their customers on a more economic basis. Through the economic planning principle, we simply require Southern, and other transmission providers, to make available to their customers services that are comparable to those they are performing on behalf of their native load. We therefore affirm the decision in Order No. 890 to require transmission providers to perform economic planning studies at the request of their stakeholders.

i. Cost Allocation for New Projects

241. In order to satisfy the cost allocation principle, transmission providers must address in their Attachment K planning processes the allocation of costs of new facilities. These cost allocation methodologies are intended to apply to projects that do not fit under existing rate structures, such as regional projects involving several transmission owners or economic projects that are identified through the study process, rather than projects built in response to individual requests for service. The Commission declined to impose a particular allocation methodology for such projects and, instead, identified three factors to be considered upon review of cost allocation proposals. First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, we consider whether the proposal is generally supported by state authorities and participants across the region.

[89] Order No. 890 at P 547.

[90] RTOs and ISOs may continue to use existing stakeholder processes to identify which economic planning studies will be of most benefit to the region, provided such processes are otherwise consistent with the requirements of Order No. 890.

[91] *See id.* at P 547.

[92] *See id.* at P 546.

[93] *See id.* at P 542.

Requests for Rehearing and Clarification

242. PSEG questions whether the Commission intended in Order No. 890 to mandate the funding of economic projects through the cost allocation methodology developed as part of the transmission provider's planning process. PSEG argues that this would be inappropriate since certain transmission providers, such as NYISO, currently only conduct reliability planning, not economic planning. PSEG argues that the most transmission providers should be obligated to do is present information so that market participants may respond to economic issues. In its view, introduction of regulated transmission solutions in response to economic enhancements destroys incentives for private investment and precludes the possibility of other market-based solutions, such as generation and demand side management, from providing a more efficient solution. PSEG objects to the Commission's reliance on the PJM ''market efficiency'' proposal, arguing that the Commission's action in that proceeding was conditioned on PJM submitting a compliance filing to clarify aspects of its proposal.[94]

243. To the extent the Commission requires ratepayer funding of economic upgrades, PSEG suggests that market participants who are asked to pay be allowed to vote on acceptance of cost allocations for the project. PSEG suggests that construction of a project be approved only if a certain percentage vote in favor of building the project and no more than a certain percentage vote against building the project. With regard to reliability upgrades, PSEG argues that there are also insufficient checks in place to ensure that RTOs and ISOs do not undertake expensive upgrades to solve a reliability criteria violation when simpler, less expensive projects may suffice. PSEG therefore requests that the Commission require that a cost-benefit analysis be conducted for both reliability and economic transmission projects.

244. TDU Systems argue that the costs of all network upgrades identified in the transmission plan be allocated and recovered on a rolled-in basis. TDU System maintain that rolled-in rate treatment for such upgrades would minimize disputes and encourage expansion by providing certainty for transmission providers. TDU Systems contend that failure to mandate rolled-in cost recovery for network upgrades identified in the transmission plan defaults on the Commission's obligations under FPA section 217 to promote expansion to support the ability of LSEs to meet their service obligations.

245. EPSA argues that any cost allocation of economic projects must be based on clear and balanced economic metrics, calculations, and assumptions. EPSA objects to any requirement that cost allocation provisions for economic projects create a funding mechanism for proponents of such projects, arguing that this would be inconsistent with the Commission's statements that transmission providers are not under an obligation to fund or build upgrades identified in the transmission plan.

246. Old Dominion urges the Commission to clarify Order No. 890 by elaborating and expanding upon the factors the Commission will consider in addressing cost allocation for new transmission. Old Dominion suggests that the following issues be considered in evaluating whether a cost allocation proposal is reasonable: facilitation of regional market development; benefits over the life of the facility; reliability benefits beyond resolution of the triggering reliability violation; reduction in capacity, energy, and reserve costs from reliability upgrades; consideration of benefits that may not be readily quantifiable; need for rate certainty; and, avoidance of rate shock. Old Dominion argues that elaboration on these factors will help stakeholders reach consensus on cost allocation issues. Old Dominion also seeks clarification that the cost allocation principle applies equally to projects that are built by a single transmission owner, but that have a regional impact.

247. With regard to interregional cost allocation, Old Dominion and TDU Systems argue that the Commission should require the cost allocation criteria identified in the transmission provider's Attachment K to apply to transmission facilities in one region that provide benefits to customers in another region.[95] Old Dominion contends that omission of cross-border allocation requirements in the OATT is inconsistent with basic cost causation principles as expressed in Order No. 890 itself.[96] TDU Systems argue that regions will benefit from up-front resolution of cross-border allocation issues, just as transmission providers benefit from up-front resolution of regional cost allocation issues.

248. E.ON U.S. asks the Commission to clarify that the cost allocation principle may not be used to shift transmission construction costs to border utilities that receive no direct benefit from the construction. E.ON U.S. contends that the transmission customers of each RTO or ISO already pay for the cost of upgrades through transmission rates charged by the RTO or ISO.

249. Duke does not object to the cost allocation principle, but notes the difficulties that have been experienced in reaching consensus in RTOs and ISOs and asks the Commission to consider delaying the requirement beyond the 210-day due date if regional consensus cannot be reached. In the alternative, Duke suggests that transmission providers be allowed to submit allocation proposals as separate informational strawmen that will serve as a vehicle for further discussion in the region.

Commission Determination

250. The Commission affirms the decision in Order No. 890 to require transmission providers to address in their Attachment K planning processes cost allocation for new facilities that do not fit under existing structures. Transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs. This applies equally to reliability and economic projects, whether built by a single transmission owner or through joint ownership. However, mandatory rolled-in rate treatment for all network upgrades identified in the transmission plans, as suggested by TDU Systems, is not necessarily appropriate. The Commission is fulfilling its obligations under FPA section 217 to support expansion of the grid by requiring transmission providers to address in their Attachment K processes how costs will be allocated for reliability and economic projects, which we will address on a case-by-case basis.

251. We disagree with PSEG's contention that economic projects should be excluded from the cost allocation provisions of the *pro forma* OATT. As the Commission noted in Order No. 890, the issue of cost allocation is particularly important as applied to economic upgrades.[97] Participants seeking to support new transmission investment need some degree of certainty regarding cost allocation to pursue that investment. We therefore agree with EPSA that the details of proposed cost allocation methodologies must be clearly defined,

[94] *Citing id.* at P 545 (citing *PJM Interconnection, LLC,* 117 FERC ¶ 61,218 (2006), *reh'g pending*).

[95] *Citing Midwest Ind. Sys. Operator, Inc.,* 117 FERC ¶ 61,241 (2006); *Midwest Ind. Sys. Operator, Inc.,* 109 FERC ¶ 61,243 (2004).

[96] *Citing* Order No. 890 at P 559.

[97] *See id.* at P 542.

but emphasize that adoption of a cost allocation methodology will not impose an obligation to build. As we reiterate above, identification of an upgrade (reliability or economic) in the transmission plan does not trigger an obligation to build under the Attachment K planning process. Up-front identification of how the cost of a facility will be allocated will, however, allow transmission providers, customers, and potential investors to make the decision whether or not to build on an informed basis.

252. As explained above, all transmission providers, including RTOs and ISOs, must undertake economic planning studies at the request of stakeholders. Within an RTO or ISO, stakeholder processes can be used to determine whether to pursue either economic or reliability upgrades and, thus, voting mechanisms such as those suggested by PSEG could be adopted if stakeholders desire. If the transmission provider or stakeholders determine that other solutions are superior to transmission upgrades, they may pursue those solutions instead and integrate them into the transmission plan. The transmission planning process established in Order No. 890 does not dictate that particular investments be made, rather that an open, coordinated, and transparent process be adopted to govern the decision-making process.

253. We decline to adopt Old Dominion's suggestion to define in more detail the factors to be considered in evaluating whether a cost allocation proposal is reasonable. We intend to allow regional flexibility regarding cost allocation and will consider each proposal on a case-by-case basis. While we would expect many of the considerations raised by Old Dominion to be relevant, since they fall within the three factors identified by the Commission, the merits of each proposal will be analyzed in light of the facts and circumstances surrounding the proposal. Similarly, issues regarding cross-border allocation or the potential shifting of costs to border utilities are best addressed in the context of a particular proposal.

254. Finally, we deny Duke's request to extend the Attachment K compliance deadline as it relates to cost allocation proposals. We acknowledge that resolution of cost allocation issues are difficult, as are many of the issues raised in the context of transmission planning. The Commission therefore granted transmission providers an extension of the Attachment K filing deadline in order to allow for a second round of staff technical conferences to review progress made on draft compliance filings.[98] Commission staff also issued a white paper to further assist transmission providers in the drafting of Attachment K tariff language.[99] We believe that transmission providers have had adequate time and guidance to complete the drafting of their Attachment K proposals prior to the revised filing deadline.

j. Additional Issues Relating to Planning Reform

(1) Independent Third-Party Coordinator

255. The Commission declined in Order No. 890 to require the use of an independent third party coordinator for transmission planning activities, but encouraged transmission providers and their customers to explore aspects of planning where the use of an independent coordinator would be beneficial and to incorporate those aspects in their planning processes.

Requests for Rehearing and Clarification

256. Old Dominion argues that the Commission erred by failing to recognize the need for an independent third party to oversee transmission planning. With regard to RTOs in particular, Old Dominion seeks confirmation that market monitoring units have the requisite independence and authority to investigate and address undue influence in the transmission planning process. Old Dominion asks the Commission to direct RTOs to include in their compliance filings a description of the market monitor's ability to identify and address undue influence in the transmission planning process. Old Dominion argues that the ability for customers to file a section 206 complaint is insufficient and can only bring about prospective changes in monitoring, failing to remedy the potential exercise of transmission market power in transmission planning.

257. TDU Systems support the decision not to mandate use of a third-party facilitator in the transmission planning process and seek clarification that, to the extend a third-party facilitator is used, related costs can be included in a transmission provider's cost of service only if all transmission customers agree or if a cost-benefit analysis supports the use of the facilitator. TDU Systems contend this would avoid disputes regarding the wisdom of using a third-party facilitator if a significant segment of transmission customers object.

Commission Determination

258. We disagree with Old Dominion that we did not adequately address the potential role of an independent third party in transmission planning in Order No. 890. As the Commission explained, there may be benefits to be gained from independent third party oversight, but transmission providers, customers, and other stakeholders should determine for themselves in developing the transmission provider's planning process whether, and if so how, to utilize an independent third party.[100] This would include considerations regarding recovery of costs associated with the use of a third-party in the transmission planning process and, within an RTO, the role of the market monitor, if any, in that process.

(2) Open Season for Joint Ownership

259. Although the Commission acknowledged in Order No. 890 the benefits of joint ownership of transmission facilities, the Commission declined to mandate open season procedures to allow market participants to participate in joint ownership. The Commission recognized that there may be reasons, given the complexity of the transmission grid and changing conditions of supply and demand for power, why any given facility identified in a transmission plan may not be ultimately constructed. If a transmission provider declines to construct an identified upgrade, the Commission encouraged customers and third parties to consider, either individually or jointly, development and ownership of a project to the extent consistent with applicable state law.

Requests for Rehearing and Clarification

260. FMPA asks the Commission to order transmission providers to make available opportunities to jointly participate in the ownership of new transmission facilities to achieve the benefits of joint ownership recognized by the Commission and remedy the discriminatory and anticompetitive effects of excluding some public power utilities from ownership. In the alternative, FMPA asks the Commission to take the lesser step of establishing presumptions that transmission customers are allowed to jointly invest in new grid transmission facilities and that transmission providers are not entitled to rate incentives if they exclude some systems that are willing to

[98] *See Preventing Undue Discrimination and Preference in Transmission Service,* 120 FERC ¶ 61,103 (2007).

[99] *Transmission Planning Process Staff White Paper,* Docket No RM05–17–000, *et al.* (August 2, 2007).

[100] *See* Order No. 890 at P 567.

invest in transmission. FMPA argues that such presumptions will prevent recalcitrant transmission owners from refusing participation or from using their control of the grid to extract unreasonable terms and conditions, while allowing them to protect any legitimate interests they may have.

261. TDU Systems argue that diversification of ownership of the grid, facilitated by mandatory open seasons for joint or third-party ownership, would provide a structural remedy to the vertical market power enjoyed by many transmission providers. They contend that the inadequacy of the grid, combined with the unwillingness or inability of transmission providers to invest in new infrastructure, has allowed many transmission providers to retain generation dominance on their systems and unduly discriminate against transmission customers. TDU Systems argue that FPA sections 205 and 206 give the Commission adequate authority to mitigate this market power by either requiring open seasons for joint ownership or third-party ownership or by conditioning market-based rate authority or incentive rates on agreements to offer such open seasons.

262. TDU Systems argue that the Commission at a minimum should require transmission providers to hold open seasons for third-party construction where a transmission provider is unwilling or unable to construct a new facility that is identified as needed in the planning process. TDU Systems further request that the Commission modify the *pro forma* OATT to include an explicit obligation to interconnect joint or third-party facilities constructed in response to projects identified in the local or regional planning process.

Commission Determination

263. The Commission affirms the decision in Order No. 890 not to mandate procedures for joint ownership of transmission facilities. We continue to believe that there are benefits to joint ownership, particularly for large backbone transmission facilities, and encourage transmission providers, customers, and third parties to consider joint development and ownership as appropriate. The Commission acknowledged in Order No. 890, however, that joint ownership can increase the complexity of planning and developing a transmission project and we are sensitive to concerns that formal open seasons can add to that complexity.[101] We therefore decline to mandate the generic use of open seasons or establish presumptions, as suggested by FMPA, regarding their use.

264. We also reject TDU Systems' suggestion that declining to mandate open seasons for joint ownership leaves the transmission provider with unmitigated vertical market power. Transmission providers are required under the OATT to make transfer capability available on a non-discriminatory basis and to expand their systems as necessary to accommodate requests for transmission service, including service associated with new customer-owned transmission facilities. In the absence of specific evidence of undue discrimination by a transmission provider, we do not believe mandating open seasons or altering our incentive rate program is necessary to mitigate market power in the provision of transmission service. Customers and third parties remain free to develop and construct facilities as they see fit and, through the Attachment K planning process, incorporate the development of those facilities into the transmission plan.

C. Transmission Pricing

1. Energy and Generation Imbalances

a. Tiered Approach to Imbalance Penalties in the OATT

265. In Order 890, the Commission modified Schedule 4 of the *pro forma* OATT regarding treatment of energy imbalances and adopted a separate *pro forma* OATT schedule (Schedule 9) to govern treatment of generator imbalances. The Commission determined that charges for both energy and generator imbalances must follow three principles: (1) The charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.

266. The Commission also determined that the same tiered approach should be used for both energy and generator imbalances. Imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) are to be netted on a monthly basis and settled financially at 100 percent of incremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or 2 to 10 megawatts, whichever is larger) are to be settled financially at 90 percent of the transmission provider's system incremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Finally, imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) are to be settled at 75 percent of the system incremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances.

Requests for Rehearing and Clarification

267. TAPS contends that the use of the phrase "same imbalance" in the language of Schedules 4 and 9 is imprecise and could lead to some confusion. TAPS asks that the Commission amend the language of Schedules 4 and 9 to be consistent with footnote 387 of Order No. 890, in which the Commission states that a transmission provider may only charge the penalty percent adder to the incremental cost for either an hourly generator imbalance or an hourly energy imbalance for the same imbalance.[102] TAPS suggests modifying the first paragraph of Schedule 9 to read: "The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or hourly energy imbalances under Schedule 4 for the imbalances occurring during the same hour, but not both (unless the imbalances aggravate rather than offset each other)." TAPS requests that the similar change be made to corresponding language in Schedule 4.

268. Steel Manufacturers Association argues that the Commission should abandon the dead band/penalty mechanism for energy imbalances and adopt instead the basic framework employed in the organized markets, where a customer pays or is paid the provider's incremental cost for imbalances. Steel Manufacturers Association contends that, in the organized markets, the Commission recognizes that pricing imbalances at the real-time price of energy provides adequate incentives to ensure that customers schedule accurately. Steel Manufacturers Association argues that the Commission failed to justify application of a different policy, *i.e.*, escalating penalties, under the *pro*

[101] *Id.* at P 594.

[102] *See id.* at P 632, n.387.

forma OATT. Steel Manufacturers Association contends that there is no evidence of negative reliability impacts in the organized markets due to the lack of inaccurate scheduling, nor is there evidence of customers taking advantage of the transmission provider by leaning on the transmission grid. Steel Manufacturers Association further contends that similar imbalance pricing policies should apply in both market structures. Steel Manufacturers Association argues that clearing imbalances outside of the organized markets at the transmission provider's marginal cost for the hour is sufficient for that purpose. If the Commission retains a Schedule 4 with a bandwidth and penalty structure, Steel Manufacturers Association requests that the Commission institute a larger bandwidth of, at minimum, 10 percent for small wholesale customers and discrete retail loads in order to provide some measure of relief for those customers.

269. Steel Manufacturers Association also requests that end-use customers that provide ancillary services through demand response be exempt from imbalance charges for imbalances created as a result of the use of the demand response. Steel Manufacturers Association contends that an end-use customer that modifies its usage in real-time, in order to be price responsive or respond to a system operator's call to curtail load, will create energy imbalances. If that end-use customer is assessed a penalty for those energy imbalances, Steel Manufacturers Association argues that it will have little incentive to provide an ancillary service such as spinning reserve or regulation through demand response. Steel Manufacturers Association suggests that the Commission revise the energy imbalance provisions to encourage, rather than discourage, demand response.

Commission Determination

270. The Commission affirms the decision in Order No. 890 to adopt a tiered bandwidth approach for both energy and generation imbalances. We disagree with Steel Manufacturers Association that simply paying the transmission provider's incremental cost for energy imbalances would provide adequate incentives for customers to schedule accurately under the *pro forma* OATT. Market structures in place within RTOs and ISOs are fundamentally different from those in non-RTO/ISO regions. In the organized markets, system operators generally use a five minute dispatch with multiple suppliers of imbalance energy responding to system operator instructions. Suppliers and customers alike are therefore able to respond to real-time changes in locational prices that reflect both the cost of energy and congestion, which serves to discipline transmission customers and generators from deviating from their instructed level. This is not the case outside of the organized markets and, therefore, other incentives must be provided to discourage deviations.

271. We also decline to institute a larger bandwidth or eliminate the penalty structure for energy imbalances caused by small wholesale customers or discrete loads. Use of the bandwidths adopted in Order No. 890, with the 2 MW and 10 MW minimums for the first and second penalty bands, appropriately links increased deviations and potential reliability impacts on the system while allowing increased tolerance to smaller customers. We note, moreever, that the 2 MW minimum specified in Order 890 does allow for a 10 percent bandwidth, as Steel Manufacturers Association requests, for loads 20 MW or less.

272. We agree with Steel Manufacturers Association, however, that end-use customers providing an ancillary service through demand response should generally not be subject to penalties for imbalances created as a result of providing the ancillary service. In this respect, customers using demand resources for ancillary services should not be treated differently from customers using generating units to provide ancillary services. The mechanisms for addressing the self-provision or third-party provision of ancillary services have developed outside the *pro forma* OATT and we will not disrupt these developments. Thus, there is no need to revise the *pro forma* OATT, as Steel Manufacturers Association suggests, since existing practices for third-party provided ancillary services should apply to demand resources as they apply to generating resources.

273. We agree with TAPS that the reference to ''same imbalance'' in Schedules 4 and 9 could lead to confusion and amend the language of those schedules accordingly. We revise the language of Schedules 4 and 9 to clarify that the transmission provider may charge a transmission customer a penalty for either hourly generator imbalances under Schedule 9 or hourly energy imbalances under Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

b. Generator Imbalance Penalties

274. The Commission concluded in Order No. 890 that formalizing generator imbalance provisions in the *pro forma* OATT will standardize the future treatment of such imbalances from the wide variety of generator imbalance provisions that previously existed in various generator interconnection agreements. Standardizing generator imbalance provisions, in turn, should lessen the potential for undue discrimination, increase transparency and reduce confusion in the industry. The Commission emphasized, however, that it was not abrogating existing generator imbalance agreements in this rulemaking proceeding.

275. With regard to intermittent resources, the Commission provided that such resources are exempt from the third-tier deviation band and would pay the second-tier deviation band charges for all deviations greater than the larger of 1.5 percent or two megawatts. The Commission defined intermittent resources for this purpose as ''an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.'' The Commission also determined that all generators should be excused from imbalance penalties that occur due to directed reliability actions by a generator to correct system frequency.

Requests for Rehearing and Clarification

276. A number of petitioners seek rehearing and/or clarification of the generator imbalance reforms adopted in Order No. 890. Sempra Global asks that the Commission revise section 3 of the *pro forma* OATT to make clear that generator imbalance service must be offered for any transmission service used to deliver energy from a generator located within the transmission provider's control area, as required in Schedule 9. Sempra Global argues that section 3 of the *pro forma* OATT is inconsistent with Schedule 9, since section 3 only requires a transmission provider to offer generator imbalance service to a transmission customer serving load within the transmission provider's control area.

277. EEI, Entergy, and Southern ask that the Commission clarify that a transmission provider is entitled to charge either the transmission customer or the generator for generator imbalance service when the customer takes transmission service to deliver energy to an off-system load. In their view, generator imbalance charges may only be assessed to a transmission customer

under new Schedule 9. Southern and EEI argue that this may be inappropriate because in many instances the generator is responsible for the generator imbalance, not the transmission customer. If the generator sells energy to more than one customer, Southern and EEI contend that it will be virtually impossible to determine which transmission customer should be assessed a charge and how the billing would be determined.

278. EEI and Southern propose changes to Schedule 9 to address these concerns. EEI asks the Commission to clarify that either the transmission customer or the generator must take generator imbalance service in connection with any off-system sale of energy and that the transmission provider has no obligation to provide transmission service on its system to an off-system load unless the transmission customer or the generator executes a service agreement committing to take generator imbalance service. Southern, however, argues that the Commission should require every generator, subject to the grandfathering provisions in Order No. 890, to execute a service agreement to take and pay for generator imbalance service pursuant to Schedule 9 of the OATT and be a transmission customer for such purposes. If the Commission does not do so, Southern asks in the alternative that the Commission clarify that transmission providers, subject to the grandfathering provisions of Order No. 890, have no obligation to provide transmission service from an on-system generator to an off-system load if such generator has not executed a service agreement under the transmission provider's OATT providing for the generator to take and pay for generator imbalance service.

279. PNM argues that transmission providers should not be required to provide generator imbalance service when doing so would impair reliability for the transmission provider. PNM contends that some control area operators may not be able to offer generator imbalance service unless they can procure balancing energy and associated capacity from another entity. PNM argues that the obligation to provide Schedule 9 service should be contingent upon the transmission provider determining that it is able to provide this service based upon a system impact study. Even if the service can physically be provided, PNM states that placing a must-offer requirement in Schedule 9, particularly for the purpose of supplying imbalance energy for intermittent generation, may have unreasonable impacts on the supply resources operated by small host control areas. In PNM's view, an absolute must-offer requirement for Schedule 9 could lead to proportionately heavy impacts on small transmission providers that are required to interconnect generation developed to serve distant urban areas within large control areas.

280. Joined by EEI and APS, PNM suggests that the Commission address these reliability concerns by allowing transmission providers the alternative of offering generators dynamic scheduling to change the responsibility for generator imbalances from specific generators. In cases where system reliability would be adversely affected, these petitioners contend that requiring a generator to accept a dynamic schedule of its output to the control area where the load is located, instead of requiring the transmission provider to provide generator imbalance service, would give the transmission provider a viable alternative to ensure that the generator's imbalances are absorbed without compromising the reliability of the system where the generator is located, while also aligning the responsibility for supplying the imbalances associated with the parties that enjoy the benefit of the generation.

281. EEI further argues that imbalance penalties fail to adequately compensate transmission providers for threats to system reliability caused by excessive generator imbalances and, therefore, use of dynamic scheduling would be appropriate. If the Commission does not allow the alternative of dynamic scheduling, APS requests that the Commission revise Schedule 9 to allow a transmission provider to identify the total amount of generator imbalance service it will offer.

282. Other petitioners request clarification or rehearing regarding the Commission's decision to exempt deviations associated with correcting system frequency from associated imbalance penalties. Xcel agrees with the Commission that generators should not be subject to imbalance penalties that occur when the generator is responding to reliability directives to correct frequency deviations and requests that this exception be expressly incorporated into the *pro forma* OATT. Xcel requests that the Commission either amend the Order No. 890 *pro forma* OATT on rehearing or clarify that a transmission provider can implement this practice by including such language in its compliance filing. Xcel suggests that the Commission also could, in the alternative, clarify that a transmission provider may implement this practice by posting a business practice indicating the transmission provider will waive such imbalance charges for generators correcting frequency deviations on a non-discriminatory basis.

283. EPSA and TAPS request that the Commission expand the exemption to include other situations in which a generator is directed to be off-schedule by transmission operators, balancing authorities, or reliability coordinators. EPSA states, for example, that generators are often given directives by balancing authorities in order to reduce unscheduled flows on other systems and/or change line flows or voltage levels. TAPS argues that there should be an exception for generator imbalances resulting from transmission loading relief procedures (TLRs) or other transmission provider instructions, and for both the unexpected loss of a generating unit and the response of other generators to replace that unit under the reserve sharing arrangements, with resulting imbalances treated as being within the first deadband. TAPS argues that penalizing imbalances in the case of forced generation outages is particularly inappropriate since such charges do not give plant operators any better incentive to schedule accurately because unplanned unit outages by their very nature cannot be predicted and scheduled.

284. Several petitioners request that the Commission clarify its definition of intermittent resources for purposes of applying imbalance charges. TAPS argues that intermittent generation should include test energy produced by newly completed units, so that generators are not unduly penalized (*i.e.*, at third-tier penalty levels) for output variations that are inherently unpredictable. EEI and AMP-Ohio argue that run-of-river hydroelectric generating facilities should be deemed to be intermittent resources because their inability to store water to produce energy on demand satisfies the intention of the Order No. 890 definition, notwithstanding the fact that strictly speaking they do not have fuel sources. Northwestern, however, argues that run-of-river hydroelectric projects should not qualify as an intermittent resource because they generally do have the ability to predict flows and schedule accurately. NorthWestern also requests that the Commission specifically require utilities to update their tariffs to reflect this new definition.

285. AMP-Ohio also argues that intermittent resources should be entirely exempt from imbalance penalties, arguing that it is unfair to impose any level of penalties on resources that are not dispatchable. In AMP-Ohio's view, wind generators and run-of-river hydroelectric facilities alike depend on uncontrollable forces that

affect their actual levels of generation. AMP-Ohio argues that fully exempting intermittent resources from imbalance penalties would not be unduly discriminatory vis-à-vis generators that are dispatchable since the different treatment would merely recognize their different circumstances.

286. Finally, Entergy asks that the Commission confirm that transmission providers do not need to seek renewal of existing generator imbalance agreements. Entergy contends that it is unclear whether the procedures described in section IV.C of Order No. 890, regarding Commission consideration of previously-approved variations from the *pro forma* OATT, are intended to apply to generator imbalance agreements that have been previously negotiated between willing parties.

Commission Determination

287. The Commission affirms the decision in Order No. 890 to adopt standardized generator imbalance provisions in Schedule 9 of the *pro forma* OATT. We agree with Sempra Global that section 3 of the *pro forma* OATT, as revised in Order No. 890, does not properly reflect that generator imbalance service must be offered for any transmission service used to deliver energy from a generator located within the transmission provider's control area, as required in Schedule 9. We revise section 3 to make this clear.

288. We also agree with EEI and Southern that, in certain circumstances, it may be appropriate for the transmission provider to allow a generator located within its control area to execute a service agreement for generator imbalance service, even if the generator is not otherwise a transmission customer. Without settling with the individual generator, it could be impossible for the transmission provider to determine which transmission customer should be assessed a charge and how the billing would be determined if a single generator was selling to multiple customers. We have revised Schedule 9 of the *pro forma* OATT to require the transmission provider to offer generator imbalance service to any generator in its control area (subject to the limitations discussed below). We clarify that, if a generator has executed a service agreement for generator imbalance service, any transmission customer scheduling from the generator will be deemed to have satisfied its obligation to purchase generator imbalance service under section 3 and Schedule 9.

289. We further clarify that a transmission provider only has to provide generator imbalance service from its own resources to the extent that it is physically feasible to do so (*i.e.*, the transmission provider is able to manage the additional potential imbalances without compromising reliability). It is not the Commission's intent to require transmission providers to provide generator imbalance service from its resources when it would unreasonably impair reliability. Each transmission provider therefore may state on its OASIS the maximum amount of generator imbalance service it is able to offer from its resources, based on an analysis of the physical characteristics of its system. Alternatively, a transmission provider may consider requests for generator imbalance service on a case-by-case basis, performing as necessary a system impact study to determine the precise amount of additional generation it can accommodate and still reliably respond to the imbalances that could occur.

290. This does not relieve the transmission provider of its obligation to provide generator imbalance service if it is able to acquire additional resources in order to do so. We acknowledge PNM's concerns that some control area operators may only be able to provide generator imbalance service by procuring balancing energy and associated capacity from another entity. If it is not physically feasible for the transmission provider to offer generator imbalance service using its own resources, either because they do not exist or they are fully subscribed, the transmission provider must attempt to procure alternatives to provide the service, taking appropriate steps to offer an option that customers can use to satisfy their obligation to acquire generator imbalance service as a condition of taking transmission service. In the unlikely circumstance that there are no additional resources available to enable the transmission provider to meet its obligation for generator imbalance service, the transmission provider must accept the use of dynamic scheduling to the extent a transmission customer has negotiated appropriate arrangements with a neighboring control area.[103]

291. We also reject requests to further exempt intermittent resources by eliminating imbalance penalties altogether for such resources. Generator imbalance charges are based on the incremental costs incurred by the transmission provider to respond to the generator's imbalance. In the second tier, charges escalate somewhat to provide an incentive for generators not to deviate outside of the first tier. Without this penalty component, intermittent resources would not have any additional incentive to accurately schedule. At the same time, the Commission recognized that intermittent generators cannot always accurately follow their schedules and therefore exempted those resources from third-tier penalties. If given proper incentives, intermittent generators can improve their forecasting methods in order to submit more accurate schedules. Thus, we continue to believe this relaxed penalty structure strikes the right balance between the need to encourage accurate scheduling and the operating limitations of intermittent resources.

292. We agree with EEI and AMP–Ohio that the definition of intermittent resources includes run-of-river hydroelectric units that do not store water used to generate electricity, *i.e.*, for which instantaneous inflow equals instantaneous outflow. Hydroelectric units using storage, however, are not intermittent resources within the meaning of Schedule 9 of the *pro forma* OATT. The ability of those units to schedule their output is not as limited as intermittent resources. The same is true of newly completed generating units producing test energy. Under the *pro forma* OATT, generators do not have to submit final schedules until the morning of the prior operating day and may revise those schedules up until 20 minutes prior to the operating hour. We conclude that this provides sufficient flexibility for hydroelectric units using storage and newly completed units producing test energy to change their schedules to reflect forecasted output and that any charges resulting from remaining imbalances are just and reasonable under the reformed generator imbalance provisions of the *pro forma* OATT.

293. We agree with Xcel that the exemption from generation imbalance penalties for generators responding to correct frequency decay should be expressly stated in the *pro forma* OATT. We also agree with EPSA and TAPS that a generator that deviates from its schedule due to directives by balancing authorities, transmission operators, and reliability coordinators should not be subject to the penalty component of imbalance charges and that this exemption should be expressly stated in Schedule 9. It would be inappropriate to assess imbalance penalties on generators following instructions to, for example, reduce unscheduled flows on other

[103] The Commission addresses request to require transmission providers to offer dynamic scheduling as a new service under the *pro forma* OATT in section III.D.1.d.

systems (such as a TLR) or change line flows or voltage levels, because such charges could create incentives not to respond and in turn compromise reliability. Similarly, generators responding to a reserve sharing event, with properly structured arrangements with transmission providers, should not be subject to penalties. We revise Schedule 9 accordingly.

294. We decline, however, to carve out an exception for imbalances associated with the loss of a generating unit itself. We disagree with TAPS that penalizing imbalances in the case of forced generation outages does not give plant operators any better incentive to schedule accurately. Appropriately designed penalties provide a proper incentive for generators to reduce instances of forced outage by, for example, properly maintaining their facilities, and therefore adhere to their schedules.

295. Finally, we reiterate in response to Entergy that the Commission did not intend to abrogate existing generator imbalance agreements as a part of this rulemaking proceeding.[104] The imbalance-related reforms do, however, apply to provisions contained in a transmission provider's OATT, including previously-approved variations from the *pro forma* OATT. Transmission providers were given an opportunity to seek continued approval of such previously-approved variations, provided the variations continued to be consistent with or superior to the revised *pro forma* OATT. We note that Entergy made such a showing with respect to the generator imbalance provisions of its OATT.[105]

c. Intentional Deviations and Intra-hour Netting

296. The Commission declined in Order No. 890 to impose generic penalties in the *pro forma* OATT for intentional deviations, concluding that the tiered imbalance penalties generally provide a sufficient incentive not to engage in such behavior. The Commission explained that proposals to assess additional penalties for intentional deviations would continue to be considered on a case-by-case basis, subject to a showing that they are necessary under the circumstances. Any such tariff provisions must include clearly defined processes for identifying intentional deviations and the associated penalties.

Requests for Rehearing and Clarification

297. South Carolina E&G argues that the Commission should grant rehearing to assess additional penalties for entities that deliberately lean on the system or, in the alternative, provide for generator imbalance settlements over a shorter period than one hour. In its view, generators unable to ramp up precisely to meet their schedules can under-generate in the initial part of the hour and then over-generate in later parts of the hour in order to integrate closer to the schedule when settled over the entire hour. South Carolina E&G contends that this practice imposes costs on balancing authorities and affects system reliability, yet does not necessarily trigger the higher-tiered imbalance charges. South Carolina E&G argues that adopting higher penalties for substantial hourly imbalances does not address the issue of intra-hour swings, which instead could be resolved by adopting 10-minute imbalance charges.

Commission Determination

298. The Commission denies rehearing of the decision in Order No. 890 not to impose generic penalties for intentional deviations. We continue to believe that it is appropriate to maintain the *status quo* of aggregating net generation over the hour in the *pro forma* OATT. To the extent a transmission provider wishes to adopt additional penalties for intentional deviations, it may do so provided it can show they are necessary under the circumstances. As the Commission explained in Order No. 890, requests to adopt a shorter interval over which to calculate imbalances also will be considered on a case-by-case basis, provided that such proposals are consistent with relevant market structures.[106]

d. Definition of Incremental Cost

299. In Order No. 890, the Commission defined incremental cost, for purposes of the tiered imbalance provisions, as the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and maintenance costs, purchased and interchange power costs and taxes, as applicable. The Commission also concluded that it was appropriate, through the definition of incremental cost, to allow for recovery of both commitment and redispatch costs, but excluded on a generic basis the cost of additional regulation reserves. The Commission emphasized that allowable costs should only be those additional costs incurred by the transmission provider due to the imbalance and, if applicable, start-up costs should be allocated *pro rata* to the offending transmission customers based on cost causation principles.

300. If the transmission provider elects to have separate demand charges to recover the cost of holding additional regulation reserves for meeting imbalances, the Commission stated that the transmission provider should file a rate schedule and demonstrate that these charges do not allow for double recovery of such costs. With regard to the real-time regulation burden imposed by merchant generation, the Commission stated that transmission providers could propose, on a case-by-case basis, separate regulation charges for generation resources selling out of the control area. The Commission concluded that the other demand costs of providing imbalance service are already provided under Schedule 3, 5, and 6 charges.

Requests for Rehearing and Clarification

301. While generally supporting the Commission's definition of incremental costs, Williams requests that the Commission further identify how each component of the transmission provider's incremental cost is to be determined. In Williams's view, a specific calculation methodology should be imposed, otherwise the definition of the incremental cost will afford transmission providers undue discretion in the calculation of imbalance charges. To remove this discretion, Williams suggests that the Commission require transmission providers to use the same components and the same methodology for the calculation of incremental costs for imbalance charges as the transmission provider (or its affiliate) uses to calculate the incremental cost of each resource for dispatching generation resources. At a minimum, Williams asks that the Commission require transmission providers to post on their OASIS the method used to calculate incremental costs for purposes of imbalance charges, along with the method to obtain each component or variable in the calculation.

302. Several petitioners argue that the Commission's definition of incremental cost for purposes of calculating imbalance charges does not properly account for the costs actually incurred to provide imbalance energy.[107] Ameren and Southern assert that failure to provide for recovery of opportunity

[104] *See* Order No. 890 at P 671.

[105] *See Entergy Services, Inc.,* 120 FERC ¶ 61,042 (2007).

[106] *See* Order No. 890 at P 722.

[107] *E.g.,* Ameren, EEI, E.ON U.S., and Southern.

costs will prevent utilities required to serve an imbalance from being made whole for forgone opportunities to sell excess energy to third parties. Ameren contends that the Commission has determined that not allowing the recovery of opportunity costs is inappropriate when the applicable rate is lower than the market clearing price.[108] Ameren argues that excluding opportunity costs unnecessarily harms the transmission provider's native load customers since the revenues that the utilities would have realized from selling their excess energy would have been credited back to those customers. Southern and E.ON U.S. ask that the Commission expressly provide that incremental costs include opportunity costs, as well as environmental costs, capacity charges, dispatch losses and other costs that the transmission provider must bear to provide the transmission customer with imbalance service.

303. Some petitioners argue that it is inappropriate to base the calculation of incremental cost on the last 10 MW dispatched to supply the transmission provider's native load.[109] EEI argues that the definition of incremental and decremental cost should be determined based on the cost to provide the last 10 MW of energy to serve the transmission provider's native load and all other contractual or franchise obligations, including the imbalance service itself. Progress Energy and EEI contend that the transmission provider almost always incurs incremental costs per kWh that are higher than the incremental costs of serving its native load because native load typically has first call on least-cost resources. As a result, EEI argues that the Commission's definition of incremental cost transfers to imbalance customers the value of the difference between the incremental cost per kWh to serve native load and the incremental cost per kWh to serve other contractual commitments, to the detriment of either the transmission provider or its native load customers.

304. MidAmerican argues that the Commission's definition of incremental cost could create an incentive to deliberately under-generate in order to receive the benefit of the transmission provider's least-cost dispatching. To provide appropriate incentives, Progress Energy asks that the Commission revise the definition to include the cost of providing the last 10 MW of energy to serve the transmission provider's native load plus third party sales, while MidAmerican argues that imbalance charges should be based on the incremental cost of the most expensive 10 MW of generation resources in service at the time the imbalance occurs. Southern contends that incremental cost should be defined based on the next (not the last) 10 MW dispatched. Southern asserts that this distinction is especially important in those instances where the cost of the next 10 MW will be significantly different than the last 10 MW, such as at the break point requiring deployment of a combustion turbine generator. Southern therefore asks that the Commission grant rehearing to establish separate definitions for incremental and decremental cost and revise the definition of incremental cost so that it is based on the next 10 MW dispatched.

305. EEI and Progress Energy also seek clarification of the definition of, and cost recovery for, decremental costs in particular. EEI contends that the definition adopted in Order No. 890 could result in the transmission provider crediting the customer an amount that exceeds the costs that the transmission provider actually avoided by accepting excess energy. EEI states, for example, that a transmission provider might decrease the output of a dispatchable unit in response to an imbalance even though it might also have a higher-cost power purchase contract with a fixed amount of energy to be delivered in that hour. EEI argues that the Commission's definition of decremental cost would require the transmission provider to pay the imbalance customer based on the higher-cost purchased power resource even though it has not avoided those costs as a result of accepting the customer's excess energy. In EEI's view, decremental cost should be defined to include costs that are avoided as a result of receiving imbalance energy.

306. Progress Energy asks that the definition of decremental cost be clarified to allow the recovery of start-up costs that are incurred in an hour different from the hour of excess imbalance. Progress Energy contends that requiring a transmission provider to accept excessive imbalance energy could force it to cycle a unit off-line in order to accommodate the energy. Progress Energy argues that the later start-up cost for the shut-down unit should be passed along to the imbalance customer, rather than shifted to the native load.

307. Other entities assert the Commission's definition of incremental cost is inappropriate in light of their particular market structure. When a joint dispatch agreement exists between the transmission provider and other balancing authorities, MidAmerican argues that the joint dispatch incremental or decremental cost should be used in place of native load since there is no identification of the transmission provider's native load other than as part of an aggregated, jointly dispatched load. MidAmerican also argues that transmission providers may have little or no native load from which to price imbalance costs in retail choice states. NorthWestern agrees that the definition of incremental cost fails to consider the circumstances of transmission providers that have little or no generation on their system. NorthWestern argues that the Commission should have expressly provided additional flexibility for such transmission providers through the definition of incremental cost instead of requiring them to file under FPA section 205 for acceptance of previously-approved imbalance pricing based on purchased power costs.

308. Entergy challenges as too narrow the Commission's decision to consider on a case-by-case basis proposals to charge separate regulation charges for generation resources selling out of the control area. Entergy states that the generator imbalance provisions of its OATT contain both a generator imbalance charge and a generator regulation charge, each of which are calculated based on the internal and external schedules submitted by independent generators. Entergy argues that this is appropriate because, regardless of whether the load is within the control area or outside the control area, the generator has a schedule with the control area that is met by control area resources. Entergy contends that applying a generation regulation charge only to external transactions would be arbitrary. Entergy requests clarification that the generator regulation service charges contained in its *pro forma* Generator Imbalance Agreement, which Entergy states was negotiated with generators on its system, continues to be acceptable.

Commission Determination

309. The Commission grants rehearing of the decision to calculate incremental costs for purposes of assessing imbalance charges based on the last 10 MW dispatched to supply the transmission provider's native load. Upon consideration of petitioners' arguments, we agree that it is more reasonable to base imbalance charges on the actual cost to correct the imbalance, which may be different than the cost of serving native load. As such, we will

[108] *Citing Xcel Energy Services, Inc.,* 117 FERC ¶ 61,127 (2006).

[109] *See, e.g.,* Ameren, EEI, MidAmerican, Progress Energy, and Southern.

modify the definition to require transmission providers to use the cost of the last 10 MWs dispatched for any purpose, *i.e.*, to serve native load, correct imbalances, or to make off-system sales. We believe this satisfies Southern's concerns and therefore decline to adopt its suggestion to separately define incremental and decremental cost for purposes of calculating imbalance charges by using the ''next 10 MW of generation dispatched'' in the incremental cost definition.

310. We also agree with Williams that, in order to provide transparency and minimize opportunities for undue discrimination, each transmission provider must provide language in its OATT clearly specifying the method by which it calculates incremental costs for purposes of imbalance charges, as well as the method it will use to obtain each component of the calculation. We direct transmission providers to include this proposed tariff language as part of the compliance filing ordered in section II.C.

311. Several entities complain that the Commission's definition of incremental cost does not properly allow for recovery of opportunity costs. The determination and calculation of opportunity costs associated with providing imbalance service will vary based on the circumstances of the transmission provider and, as such, we do not believe that it is appropriate to amend the definition of incremental cost in the *pro forma* OATT to address opportunity costs. We will therefore continue to consider proposals to include recovery of legitimate and verifiable opportunity costs on a case-by-case basis consistent with Commission precedent.[110] Such proposals must clearly explain how opportunity costs would be determined and demonstrate that the recovery of opportunity costs would not lead to over-recovery of costs. Similarly, transmission providers participating in joint dispatch agreements or otherwise procuring imbalance energy from other generators may need to have alternative definitions of incremental cost. Proposals to adopt a modified definition of incremental cost to reflect the transmission provider's particular circumstances also will be considered on a case-by-case basis.

312. With regard to the definition of incremental cost in particular, we clarify that transmission providers can include in the calculation of incremental cost start-up costs that are incurred in an hour different from the hour of excess imbalance, provided that the costs are in fact associated with providing imbalance service. We disagree with EEI with respect to its description of incremental costs. The fixed amount power purchase contract in EEI's example should not be used in calculating incremental costs because it would not be included in the last 10 MW of generation dispatched by the transmission provider. In the case that a transmission provider is ramping down generation in an hour, the additional costs of the last 10 MW dispatched by the transmission provider should be used in calculating incremental costs for the purpose of financially settling imbalances.

313. In response to Entergy, we clarify that transmission providers may propose to assess regulation charges to generators selling in the control area, as well as generators selling outside the control area, and that the Commission will consider such proposals on a case-by-case basis, as we have in the case of Entergy's *pro forma* Generator Imbalance Agreement. In accordance with the procedures established in Order No. 890, Entergy sought continued approval of its generator imbalance provisions, including the assessment of generator regulation charges. The Commission accepted this variation as consistent with or superior to the *pro forma* OATT, based on the particular circumstances presented by Entergy.[111] We will continue to consider requests to assess regulation charges on generators on a case-by-case basis upon consideration of the facts and circumstances presented.

e. Inadvertent Energy Treatment

314. The Commission found in Order No. 890 that inadvertent energy is not comparable to energy and generator imbalances and, therefore, allowed inadvertent energy to be treated differently from imbalances. The Commission explained that variables affecting inadvertent interchange often depend on the actions or the omissions of utilities other than the individual transmission providers and are distinct from those resulting in energy and generator imbalances. The Commission concluded that the historic practice of paying back inadvertent interchange in kind has not proven to have adverse effects on reliability.

Requests for Rehearing and Clarification

315. TDU Systems contend that the Commission's acceptance of in-kind compensation for interchange energy undermines its rejection of requests to allow transmission customers to address monthly imbalances with in-kind transfers. TDU Systems argue that there is no evidentiary basis for the Commission to conclude that transmission providers have little control over the causes of system imbalances. TDU Systems state that transmission providers typically control 80–90 percent of the load on their systems and the dispatch of resources to serve that load. In TDU Systems' view, both transmission provider and transmission customer imbalances result from circumstances beyond their control, namely: telemetry failure, meter error, generator governor response to system problems, human error, uncontrollable load forecast errors due to rapidly changing weather, and under- or over-supply of generation.

316. TDU Systems state that deviations between load and supply, whether in the form of energy imbalances or inadvertent energy, each require adjustment or compensation and that there is no reason why that adjustment or compensation should be different among transmission users. TDU Systems argue that failure to allow for in-kind payment for imbalances within the month provides a competitive advantage to transmission providers and constitutes undue discrimination in violation of the FPA. In their view, the Commission remedied this discrimination within RTOs by requiring in Order No. 2000 that the same imbalance rules apply to transmission users and control area operators.[112] TDU Systems argues that the Commission fails to explain its departure from its resolution of this issue in the RTO context and that it is irrelevant that transmission providers may have historically paid back inadvertent interchanges with in-kind transfers without problem.

Commission Determination

317. The Commission denies rehearing of the decision in Order No. 890 to allow inadvertent energy to be treated differently from energy and generator imbalances. As the Commission explained in Order No. 890, inadvertent energy is not comparable to energy and generation imbalances and the variables affecting each are distinct. It is therefore

[110] *See* Order No. 888 at 31,740.

[111] *See Entergy Services, Inc.,* 120 FERC ¶ 61,042 at P 66 (2007).

[112] *Citing Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,142 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001).

appropriate to treat inadvertent energy and imbalances differently notwithstanding the fact that both inadvertent exchanges and imbalances may be beyond the control of the transmission provider or customer, respectively.

318. Our primary concern with respect to inadvertent energy continues to be avoidance of incentives that could degrade reliability. To date, the return-in-kind approach to inadvertent energy has proven adequate as a general matter. Petitioners do not present any evidence that in-kind payment of inadvertent energy is no longer sufficient to maintain reliability or allows certain entities to lean on the grid to the detriment of other entities. We disagree that this treatment of inadvertent energy is inconsistent with Order No. 2000. There the Commission required both control area operators and transmission customers within an RTO to clear imbalances through a real-time balancing market.[113] In the absence of a real-time balancing market, we continue to believe it is appropriate for transmission providers operating under the *pro forma* OATT to treat inadvertent interchange differently than customer imbalances.

f. Netting of Energy and Generator Imbalances

319. In Order No. 890, the Commission concluded that it is not appropriate to require transmission providers to allow netting of generator and energy imbalances outside of the tier one band. While the Commission recognized that allowing transmission customers to net energy and generator imbalances would have competitive benefits and enhance comparability, the Commission determined that it could lessen the incentive for accurate scheduling and, in turn, increase imbalances that create reliability or economic issues for specific areas of the system.

Requests for Rehearing and Clarification

320. Several petitioners ask that the Commission clarify that netting and settling within the first deviation band should be done on a financial basis, based on hourly incremental and decremental costs, rather than netting imbalances on the basis of megawatt-hours of imbalance and settling the net imbalance on a financial basis.[114] EEI, MidAmerican and Progress Energy assert that otherwise customers would be able to offset energy shortfalls in on-peak, high-cost periods against excess energy in off-peak, lower-cost hours, which would inappropriately shift costs to native load customers. If imbalances are netted based on megawatt-hours prior to financial settlement, EEI and Progress Energy argue that it would be impossible to calculate charges for net imbalances at the end of the month because the transmission provider would not be able to correlate monthly net imbalances with hourly incremental and decremental costs without exercising subjective judgment. Southern and EEI contend that the Commission, at a minimum, should require the imbalances to be netted separately for on-peak periods and off-peak periods if it determines that imbalances should be netted on a megawatt-hour basis. EEI suggests that the price for net first tier imbalances then be based on each month's average incremental and decremental costs, calculated separately for on-peak periods and off-peak periods.

321. Other petitioners assert that the Commission should allow netting outside of the first tier band.[115] Ameren argues that the threshold of the first tier band is unnecessarily low, suggesting it would be more appropriate to allow imbalances of less than 10 MW to be netted. For imbalances from 10 MW up to as much as 50 MW, Ameren suggests that the Commission allow netting of imbalances equal to the greater of 10 MW or 50 percent of its scheduled amount. TDU Systems argue that transmission customers should be allowed to net all imbalances across the transmission system within a month, reflecting appropriate differences for imbalances incurred during peak and off-peak hours. TDU Systems contend that netting should be unrestricted within the month so long as the results keep the transmission provider economically whole. TDU Systems argue that there is no evidence that netting creates reliability problems and that limiting netting is not comparable to the transmission provider's treatment of imbalances of its retail native load, generation affiliates, and marketing affiliates. TDU Systems also argue that restricting netting within the month is an unexplained departure from the Commission's treatment of natural gas pipeline imbalances.

322. NRECA asks the Commission to confirm, either on clarification or rehearing, that separate imbalance charges may not be assessed on each of a customer's separate transactions on an interface or within a control area in a single hour. NRECA contends that a customer's contribution to area control error (ACE) on a given interface is no more than the aggregate difference between schedules and deliveries and, therefore, its impact on the balance of resources and loads within a control area is no more than the aggregate difference between its resources' output and its load. If a transmission provider's system is so underdeveloped that constraints prevent transactions sourcing at different locations within the control area from being treated comparably, the Commission should require the transmission provider to upgrade its system rather than penalize the customer with multiple sets of imbalance charges on separate transactions.

Commission Determination

323. The Commission affirms the decision in Order No. 890 to allow netting of imbalances within the first tier deviation band. As the Commission explained in Order No. 890, there is a tradeoff between allowing customers to net imbalances, which would enhance comparability between the transmission provider's dispatch and the customers serving load, and the need to create incentives to limit customer imbalances due to the reliability or economic issues they can cause for specific areas of the system.[116] Netting can cause problems because it lessens the incentive for transmission customers to schedule accurately and inaccurate schedules, in turn, can require actions by the transmission provider even when imbalances offset. We believe the Commission struck the appropriate balance in Order No. 890 between the customer's need for flexibility and the transmission provider's need for accuracy and, therefore, deny TDU Systems' request to require netting of imbalances outside the tier one band and Ameren's related request to expand the tier one band for purposes of netting.

324. We also deny NRECA's request that separate imbalance charges not be assessed on each of a customer's separate transactions on an interface or within a control area in a single hour. Where transmission constraints exist, a customer whose load and generation was on net equal could still have an effect on the transmission system if some generation is ramping up to respond to some imbalances while other generation is ramping down exactly at the same time. We disagree with TDU Systems that our decision is an unexplained departure from the Commission's treatment of natural gas

[113] *See* Order No. 2000 at 31,142.

[114] *E.g.,* EEI, MidAmerican, Southern, Progress Energy, and Entergy.

[115] *E.g.,* TAPS, Ameren, and TDU Systems.

[116] *See* Order No. 890 at P 715.

pipeline imbalances. Natural gas pipelines frequently have opportunities to use storage and line pack to absorb day-to-day imbalances. Individual pipelines have tailored their imbalance requirements, including penalty provisions as needed, to meet their specific circumstances. The transmission of electricity, in contrast to the transportation of natural gas, requires instantaneous balancing which makes the need for imbalance provisions on a shorter-term basis important for the protection of reliability. NERC has created standards such that each control area is responsible for managing its Area Control Error and operating within line limits in order to protect reliability. Imbalances created by transmission customers impose an additional burden on the transmission provider to manage imbalances within the hour (as well as shorter time periods) justifying a different tariff approach under the *pro forma* OATT. As such, the imbalances provisions adopted in the *pro forma* OATT are used to protect reliability during the applicable time period.

325. With regard to netting within the tier one band, we clarify that netting should be done on a megawatt-hour basis, rolling over the month. Imbalances remaining at the end of the month should be settled at the load weighted average of the hourly incremental costs during that month.[117] We decline to require that imbalances be netted separately for on-peak and off-peak periods. Netting only applies to imbalances within the tier one band, which are relatively minor and largely within the normal range of uncertainty that cannot be avoided even under optimal operating conditions. We therefore disagree that it is necessary to adopt a more granular imbalance pricing mechanism when netting imbalances within the first tier. However, if a transmission provider finds that its customers are arbitraging on-peak and off-peak prices within the first tier, it may propose a more granular approach to netting subject to a showing that it is necessary under the circumstances.

g. Distribution of Penalty Revenues Above Incremental Cost

326. With regard to revenues received through imbalance charges, the Commission required transmission providers to develop a mechanism for crediting such revenues to all non-offending transmission customers, including affiliated transmission customers, and the transmission provider on behalf of its own customers. The Commission concluded that such distribution of revenues recognizes that transmission providers bear the responsibility to correct imbalances and often use their own facilities to do so.

Requests for Rehearing and Clarification

327. Ameren contends that the transmission provider should be allowed to keep all the penalty revenues associated with correcting imbalances and that development of a credit mechanism imposes an unnecessary and unwarranted administrative burden on transmission providers. Ameren argues that the transmission provider should receive any amounts above its incremental costs of providing imbalance service as a contribution towards the fixed costs of providing this service and that any revenues from penalties assessed on customers for leaning on the system should be credited to long-term firm transmission customers.

328. TDU Systems, however, object to the Commission's decision to allow transmission providers to retain a portion of the imbalance penalty revenues for their own retail customers. TDU Systems contend that transmission providers do not pay imbalance penalties when they over- or under-schedule their loads and, thus, receipt of related penalty revenues by transmission providers would constitute a windfall. TDU Systems argue that the Commission failed to explain its departure from *Carolina Power & Light*[118] because the Commission's decision in that case to deny credits to CP&L on behalf of its retail customers was based on those customers not being subject to energy imbalance penalties in the first place. TDU Systems contend that this fundamental paradigm has not changed with reform of the OATT.

329. MidAmerican requests clarification that it is appropriate to propose its imbalance penalty distribution mechanism in the compliance filing containing the non-rate terms and conditions of the *pro forma* OATT. Joined by NorthWestern and Mark Lively, MidAmerican also requests guidance as to the particular information the Commission would require in those filings with regard to the penalty distribution mechanism. NorthWestern asks the Commission to specify how the transmission provider should determine what customers are non-offending and over what period of time. Mark Lively seeks clarification of the time frame during which there is to be a matching of penalty revenue and credits to non-offending customers. If the matching is done on a monthly basis, Mark Lively contends that most if not all transmission customers will be found to be offending at some time during the month and thus not be eligible to be in the class of customers to receive a credit for part of the penalty revenue collected by the transmission provider. Mark Lively suggests an alternative crediting mechanism to synchronize penalties and credits by having the variance from full incremental cost be uniform for any hour or any intra-hour period, with revenues from over-deliveries shared with non-offending load and revenues from under-deliveries shared with non-offending supply.

330. NorthWestern also asks the Commission to expressly confirm that the transmission provider is not required to distribute penalty revenues until after it recovers all costs (including any associated transmission costs) incurred in providing imbalance service. NorthWestern contends that the market for such services is limited and, as a result, it has had to contract with entities located outside its control area for system balancing and load following services in order to provide imbalance service.

Commission Determination

331. The Commission affirms the decision in Order No. 890 to require transmission providers to credit revenues from imbalance charges in excess of incremental costs to all non-offending customers, including affiliates, and the transmission provider on behalf of its retail customers. As the Commission explained in Order No. 890, transmission providers with significant imbalance penalties have been required in the past to develop a mechanism to credit penalty revenues to non-offending transmission customers.[119] We disagree with Ameren that this imposes an unreasonable administrative burden on transmission providers. We note that Ameren did not seek rehearing of the decision to require transmission providers to develop a similar mechanism to distribute unreserved use penalties to non-offending customers, discussed in section III.C.4.b.[120] We would not

[117] For example, if a generator had 5 imbalances within the first deviation band in a month of +2 MWh, −6 MWh, +4 MWh, −2 MWh, −1 MWh, the net MWh imbalance for the generator at the end of the month would be −3 MWh. The generator would pay the transmission provider for 3 MWh at the load weighted average of the hourly incremental costs during that month.

[118] 103 FERC ¶ 61,209 (2003) (*CP&L*).

[119] *See* Order No. 890 at P 727 (*citing CP&L*, 103 FERC ¶ 61,209 at P 25; *Entergy Services, Inc.*, 105 FERC ¶ 61,319 (2003), *reh'g denied*, 109 FERC ¶ 61,095 (2004)).

[120] *See id.* at P 860–61.

expect development of that distribution mechanism to be any more burdensome than distributions of imbalance penalty revenues.

332. We also disagree with TDU Systems that the transmission provider on behalf of its native load customers should be excluded from the distribution of imbalance revenues. Transmission providers bear the responsibility to correct imbalances, often using their own facilities to do so, and thus their receipt of imbalance revenues does not constitute a windfall. While it is true that the Commission in *CP&L* considered relevant the fact that CP&L's customers were not subject to imbalance charges, the Commission expressly rejected CP&L's proposal to retain revenues because it would have been "contrary to the Commission's objective to eliminate incentives for transmission providers to use penalties as a profit center." [121] The imbalance charges adopted in Order No. 890 more closely relate to incremental cost and therefore minimize any incentive on the part of the transmission provider to rely on penalty revenues rather than seeking other methods of encouraging accurate scheduling. Under these circumstances, there remains no reason to exclude the transmission provider from receiving an appropriate share of penalty revenues.

333. Regarding the time frame during which there is to be a matching of penalty revenue and credits to non-offending customers, we clarify that the transmission provider should distribute the penalty revenue received in a given hour to those non-offending customers in that hour, *i.e.*, those customers to whom the penalty component did not apply in the hour. Customers that were out of balance, but within the first tier, should therefore be included in the distribution. Since most transmission customers will be out of the first deviation band at some hour during the month, we agree that it would not be appropriate to exclude these customers from receiving a *pro rata* portion of penalty revenues in the other hours. In response to NorthWestern, we clarify that the transmission provider, as part of its distribution methodology, may address how distributions may be affected by the transmission provider's inability to recover the costs incurred to provide imbalance service.

2. Credits for Network Customers

a. Severance of Credits and Planning

334. In Order No. 890, the Commission adopted the NOPR proposal to sever the link in the *pro forma* OATT between joint planning and credits for new facilities owned by network customers. The Commission concluded that linking credits for new facilities to a joint planning requirement can act as a disincentive to coordinated planning, which is contrary to the Commission's original objective in adopting the provision. The Commission also concluded that the coordinated planning initiatives adopted in Order No. 890 will ensure that most, if not all, transmission facilities are planned on a coordinated basis, notwithstanding the severance of the link between credits for new facilities and joint planning.

Requests for Rehearing and Clarification

335. E.ON U.S. argues on rehearing that the Commission failed to adequately address comments suggesting that severing the link will excuse network customers from participating in the joint planning process and permit a network customer to build facilities without oversight or input from a transmission provider. While Order No. 890 places an affirmative burden on the transmission provider to coordinate long-term transmission planning, E.ON U.S. states that no corresponding obligation is placed on the transmission customer. E.ON U.S. argues that transmission service credits for facilities constructed by network customers should be available only when the facility is jointly planned with the transmission provider.

336. NorthWestern agrees, arguing that if a network customer is permitted to construct facilities and later declare them to be worthy of a credit, such facilities will not serve the overall grid as efficiently as jointly planned facilities. NorthWestern also argues that severing the link will lead to protracted litigation regarding what facilities qualify for credits. To ensure efficient coordination of facility planning, NorthWestern requests that the Commission reconsider its decision to sever joint planning and transmission service credits.

Commission Determination

337. E.ON U.S. and NorthWestern both argue that, by severing the link between joint planning and credits for network customers, the Commission is sacrificing the benefits that resulted when a transmission provider made credits available as part of its centralized planning process. We disagree. As the Commission explained in Order No. 890, the linkage between credits and joint planning gave the transmission provider an incentive to deny coordinated planning to avoid granting credits for customer-owned facilities.[122] Therefore, it was necessary to sever the link between credits and joint planning. Any efficiencies that may be lost by severing that link should be offset by the increased efficiencies resulting from the coordinated planning initiative required in Order No. 890, which the Commission noted will ensure that most, if not all, transmission facilities are planned on a coordinated basis.[123] With the clarifications provided below, we do not expect that severing the link between joint planning and credits will lead to unnecessary litigation.

b. The New Test To Determine Eligibility for Credits

338. In Order No. 890, the Commission declined to adopt the credits test for new facilities proposed in the NOPR and, instead, revised the test to more accurately reflect the Commission's intent as expressed in the NOPR. A transmission customer is required to meet the integration standard under *pro forma* OATT section 30.9 to receive a credit for its facilities. Under the integration standard, the customer must demonstrate that its facilities not only are integrated with the transmission provider's system, but also provide additional benefits to the transmission grid in terms of capability and reliability and can be relied on by the transmission provider for the coordinated operation of the grid.[124] Because joint planning will no longer be required to obtain credits, the Commission noted that it is particularly important in this context to require a showing that a network customer's facilities provide benefits to the transmission provider's grid. To ensure comparability, the Commission adopted the presumption of integration for transmission customer facilities that, if owned by the transmission provider, would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the *pro forma* OATT.

Requests for Rehearing and Clarification

339. NRECA, TAPS and the TDU Systems request that the Commission confirm that the integration requirement under Order No. 890 does not require a more stringent standard for network customer facilities than for transmission provider facilities or in any way

[121] *CP&L*, 103 FERC ¶ 61,209 at P 26.

[122] *See* Order No. 890 at P 735.

[123] *See id.* at P 736.

[124] *See id.* at P 754, n.436 (*citing Southwest Power Pool, Inc.*, 108 FERC ¶ 61,078 (2004), *reh'g denied*, 114 FERC ¶ 61,028 (2006)).

compromise the language in section 30.9 of the *pro forma* OATT. NRECA argues that the language in Paragraph 754 of Order No. 890 and, in particular the affirmation of the ''benefits to the grid'' test in footnote 436, contradict section 30.9 by establishing an explicitly different and harder test for transmission customer facilities than for transmission provider facilities. Other petitioners agree,[125] requesting that the Commission explain that it did not intend to impose the ''additional benefits to the grid'' and ''relied on by the transmission provider'' criteria (which they state are not required for a transmission provider's facilities) on a network customer's facilities.

340. Several petitioners argue that an integration standard requiring the showing of benefits to the grid is unduly discriminatory because it maintains the presumption that a transmission provider's transmission facilities provide benefits while requiring a network customer to make an affirmative showing that its facilities provide benefits to qualify for credits.[126] FMPA and TDU Systems argue that comparability requires the same presumption of integration to be applied to all transmission facilities. To provide certainty for those building new infrastructure, TDU Systems contend that the Commission should require transmission providers to credit third parties for the costs of new facilities in a manner comparable to the compensation provided for a transmission provider's comparable facilities.

341. APPA contends that the presumption of integration is confusing because it is unclear how a network customer would make a showing that facilities would be eligible for inclusion in a transmission provider's revenue requirement if owned by the transmission provider or what the specific legal effect would be if the network customer succeeded in making such showing. APPA suggests that the Commission require credits if the customer can show that the transmission provider includes in its own revenue requirement or gives credits to other customers for facilities similar to those for which the networks customer seeks credits.

342. In implementing the presumption of integration to obtain credits, TAPS and APPA maintain that the Commission cannot require a network customer to show more than that its facilities are comparable to similar facilities the transmission provider actually includes in its rate base. TAPS argues that the Commission should clarify that the presumption cannot be overcome by evidence that the transmission provider and the transmission provider's other customers do not use or directly benefit from the customer-owned facilities. TAPS therefore requests that the Commission make clear that it will not follow precedents developed in credit cases decided under the original OATT section 30.9 regarding the types of ''benefits'' provided by a customer's facilities. Specifically, TAPS argues that a network customer of a transmission provider that includes the cost of facilities (including radials) that are used solely to serve the transmission provider's retail customers must be able to use the Order No. 890's presumption to obtain credits for similar facilities that serve only that transmission customer's retail customers.

343. FMPA also oppose any implementation of the Commission's integration test that treats customers and transmission providers differently. FMPA argue that, if a customer's facilities are necessary to serve the customer's load, the customer should be provided a credit since the transmission provider includes in rate base the cost of its facilities used to serve load. In their view, the same presumption of integration applies to all transmission facilities, *i.e.*, that transmission is integrated when, if owned by the transmission provider, it would be includable in rate base. FMPA cite legislative history and the court's decision in *TAPS* v. *FERC*[127] in support of their argument that the comparability principle is central to the issue of cost recognition for customer facilities. FMPA contend that recognizing their members' transmission through credits is beneficial because it involves all owners in joint planning and the exchange of information that results in grid construction and operation that will better serve the needs of all consumers. Without this role in joint planning, less reliable transmission and fewer generation and power supply options for systems will result. In addition, if credits are denied, FMPA will be inhibited from contributing necessary capital to the grid and likely result in reduced public support for transmission construction.

344. Other petitioners contend that the Commission should eliminate any presumption that a network customer is entitled to credits, arguing that the presumption violates the cost-causation principle by shifting costs to customers for whom the facilities were not planned and who are not benefited by their use.[128] These petitioners contend that a network customer's facilities are not planned around the needs of the transmission provider to meet its obligations and many customer facilities are designed only to pick up power from the transmission provider's grid and deliver it to that network customer's distribution network.[129] These petitioners request that the Commission allow for credits only when the customer's facilities provide a benefit to the transmission provider's grid, *i.e.*, when the transmission provider relies on a network customer's facility to serve the transmission provider's transmission customers (including the network customer seeking credits) or the transmission provider's retail customers. They argue that there is no basis to presume integration simply because the transmission provider would include the cost of such facilities were it the owner.

345. South Carolina E&G argues a presumption of integration will encourage customer overbuilding paid for by a transmission provider's native load customers. South Carolina E&G asks that the Commission confirm that it is not departing from the decade-old two-part test for credits for customer-owned facilities that requires that the facilities are both integrated into the network grid and provide benefits to the grid. South Carolina E&G disagrees that any revision to that test is required by comparability. In its view, customer-owned facilities are not comparable to transmission provider-owned facilities for purposes of credit eligibility, since each are built for different purposes and are subject to different regulatory oversight.

346. Florida Power argues that the application of the rebuttable presumption may impact reliability. Florida Power contends that, under the new test for credits, a transmission provider must show that it does not need the network customer's facilities to provide transmission service to any other customer in order to deny credits. Florida Power states that this could result in a network customer being denied credits for a facility even if the transmission provider needs the facility to reliably serve the network customer.

347. Entergy and Florida Power also request that the Commission change its policy of applying a stricter standard to a transmission provider's own facilities

[125] *E.g.,* TAPS and TDU Systems.

[126] *E.g.,* APPA, FMPA, NRECA and TAPS.

[127] 225 F.3d 667, 681 (D.C. Cir. 2000), *aff'd sub nom., New York* v. *FERC,* 535 U.S. 1 (2002).

[128] *E.g.,* Entergy and Florida Power.

[129] *E.g.,* Entergy, Florida Power and South Carolina E&G.

when a network customer has been denied credits. These petitioners state that, when the Commission denies credits for customer-owned facilities, it applies the same integration test to the transmission provider's facilities as that applied to the network customer's facilities. The petitioners argue that application of the integration test to the transmission provider's facilities in that instance is unreasonable since the nature of those facilities does not change. They argue that different tests for transmission providers and network customer systems are appropriate since each are planned for and used differently. In their view, concerns about comparability can be addressed by allowing a transmission provider's looped facility to be rolled into rate base only if the transmission provider uses the facility to serve a transmission customer or the transmission customer's retail customers.

348. Entergy and Florida Power further claim that the Commission's approach is inconsistent with the treatment of generator interconnections because the Commission's policy entitling an interconnecting generator to credits against transmission charges does not change simply because the Commission has denied a network customer credits. These petitioners contend that an interconnecting generator could be entitled to credits when at the same time the transmission provider could be prohibited from rolling the costs of those credits into its rates.

Commission Determination

349. The Commission denies rehearing of the decision in Order No. 890 to modify the credits test for new customer-owned facilities. In Order No. 890, the Commission explained that it was retaining the existing integration standard, but adopting a new presumption of integration for customer-owned facilities that would be included in rate base if owned by the transmission provider.[130] The integration standard to be applied to new facilities under section 30.9 therefore remains unchanged, so Commission precedent regarding application of the standard will continue to apply. Specifically, to satisfy the integration standard set forth in section 30.9 of the *pro forma* OATT, it must be shown that a new facility is integrated with a transmission provider's system, provides additional benefits to the transmission grid in terms of capability and reliability, and can be relied on by the transmission provider for the coordinated operation of the grid.[131] However, in recognition of the new requirement for transmission providers to plan their system on an open and coordinated basis, a customer's transmission facilities will be presumed to be integrated if the facilities, if owned by the transmission provider, would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the *pro forma* OATT.

350. The adoption of this presumption is necessary to ensure comparability between network customers and transmission providers serving native load. It is reasonable to presume, without application of any particular standard or test, that the transmission provider's facilities benefit the network because they are planned, constructed and owned, from the beginning, by the transmission provider to meet its obligations to its customers. In comparison, because customer-owned facilities are generally constructed to serve that individual customer's needs, the Commission requires the customer to satisfy the integration standard in order to qualify for credits. The Commission concluded in Order No. 890 that it is now reasonable to presume that any new customer-owned facilities satisfy the integration standard, to the extent they would be included in the transmission provider's revenue requirement if they were owned by the transmission provider, in light of the requirement imposed on transmission providers to implement an open and coordinated transmission planning process that applies to all transmission facilities.

351. To the extent necessary, we clarify that these presumptions of integration are rebuttable both as applied to the transmission provider and the network customer. For the network customers' facilities, transmission providers may challenge the presumption that the customer's facilities are integrated by showing they do not actually meet the integration standard, notwithstanding the fact that they are similar to facilities in the transmission provider's rate base. Similarly, the presumption that a transmission provider's facilities benefit the network could be overcome by a showing that the facilities, in fact, do not provide such benefit. By allowing the presumptions of integration to be rebutted, the Commission will ensure that only the costs of facilities that are actually part of the integrated network that serves all customers will receive credits. It also serves as an incentive for the transmission provider to give credits to network customers that own integrated facilities and remove from its rate base its own non-integrated facilities.

352. In light of the modifications to the credits test adopted in Order No. 890, we further clarify that denial of credits for a network customer no longer triggers a need for the transmission provider to demonstrate that its own facilities satisfy the integration standard, because credits for network customer facilities can now be denied only after an affirmative showing by the transmission provider that its facilities are not similar under the integration test to those of the network customer (*i.e.*, by overcoming the presumption of integration). This approach departs from the approach adopted in *FP&L*,[132] but reflects the fact that the new rebuttable presumption in favor of the transmission customer has shifted the burden to the transmission provider to provide evidence that credits for the customer are not warranted.

353. To provide clarity regarding how to implement the presumption that a network customer's facilities are integrated, we make clear that a network customer may justify application of the presumption by reference to the existing facilities in the transmission provider's rates. A customer need only show that its new facilities are similar in design and purpose to facilities owned by the transmission provider that are included in rates. A transmission provider may overcome the network customer's presumed integration by demonstrating, with reference to its own facilities that meet the integration standard, that the network customer's new facilities do not meet the standard. To the extent there are disputes regarding whether a customer's new facilities are sufficiently similar to those in the transmission provider's rate base, we encourage transmission providers and customers to resolve those disputes informally or with the assistance of the Commission's Dispute Resolution Service.

354. We reject requests to eliminate the presumption of integration for new customer-owned facilities, as advocated by certain transmission providers. The planning-related reforms adopted in

[130] Order No. 890 at P 753–754.

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

[132] *Florida Mun. Power Agency* v. *Florida Power and Light Co.,* 74 FERC ¶ 61,006 at 61,010 (1996) (finding that the integration of facilities into the plans or operations of a transmitting utility is the proper test for cost recognition), *reh'g denied,* 96 FERC ¶ 61,130 at 61,544–45 (2001), *aff'd sub nom. Florida Mun. Power Agency* v. *FERC,* 315 F.3d 362 (D.C. Cir. 2003).

Order No. 890 will ensure that a process exists to jointly plan all transmission facilities, including new facilities developed by customers. Comparability requires that transmission providers and customers alike benefit from a presumption of integration. It is also appropriate for both the transmission provider and its customers to be subject to the integration standard to the extent the presumption of integration is overcome, notwithstanding any coordinated planning of those facilities. Under Order No. 890, the Commission therefore will not apply, as some petitioners imply, a different or stricter standard to a transmission provider's own facilities when a network customer has been denied credits.

355. We disagree with claims that a presumption of credits for certain customer-owned facilities will encourage over-building or harm reliability. Facilities owned by transmission providers have long enjoyed a presumption of integration, yet petitioners do not object to the presumption as applied to those facilities. Petitioners offer no reason to believe that application of a comparable presumption for new customer-owner facilities would lead to reliability or operational difficulties, particularly in light of the obligation for transmission providers under Order No. 890 to plan their transmission systems on an open and coordinated basis.[133] We also believe that it is unlikely that a transmission provider would be required to provide credits to an interconnecting generator, but be prohibited from rolling the same credits into its rates. Nevertheless, should any such circumstance arise, the transmission provider should bring the issue to the Commission's attention for resolution.

c. Application of the New Test to Existing Facilities

356. In Order No. 890, the Commission concluded that the new test for determining credits will apply only to transmission facilities added subsequent to the effective date of Order No. 890. The Commission found that there is no reason to revisit the determinations with respect to the number of customer-owned transmission facilities that have been developed, and resulted in credits negotiated and litigated, under the prior test that the Commission determined to be just and reasonable at the time.[134] On a prospective basis, however, given the increased planning and coordination required in Order No. 890, the Commission stated that it is appropriate to apply the new test for determining credits.

Requests for Rehearing and Clarification

357. Several petitioners contend that it is inappropriate for the Commission to conclude that the newly announced test for determining credits under OATT section 30.9 will apply only to transmission facilities added subsequent to the effective date of Order No. 890, arguing that the Commission should remedy past undue discrimination against network service customers such as the failure of transmission providers to jointly plan facilities with transmission customers.[135] APPA also asks that the Commission explain why this result is legally appropriate.

358. NRECA contends that the Commission should apply the new test for transmission credits to both existing and new facilities, but clarify that existing credit agreements or determinations will not be impacted. NRECA argues that *Mobile-Sierra* concerns can be avoided by applying the new test to facilities that are built but not yet the subject of a credits agreement or determination. APPA suggests that allowing network customers to obtain credits going forward for existing facilities that are comparable to those the transmission provider includes in its revenue requirement would be a reasonable remedy for past discrimination. Noting the Commission's requirement for transmission providers to remove all generator step-up facility costs from their transmission rates (not only those costs incurred after the Commission changed its policy in Order No. 888), TAPS maintains that the ''correct and fair approach'' is to prospectively remedy such discrimination by applying the new standard to both existing and new facilities.[136] To do otherwise would, in TAPS' view, undermine comparability.

359. TDU Systems argue that the Commission cannot endorse rates that it knows are unjust and unreasonable and, therefore, agree that transmission customers should be credited for transmission facilities regardless of their vintage to the extent the facilities have not been subject to a prior determination. TDU Systems contend that Order No. 890 failed to adequately justify allowing rates to remain in place that reflect undue discrimination. FMPA argue that comparability similarly requires that the Commission apply the presumption of integration to existing as well as new customer-owned facilities, since both existing and new transmission provider-owned facilities are presumed to provide benefits to the grid.

360. Entergy and Florida Power ask that, to the extent the Commission applies the new test to transmission provider facilities, the rule apply only to new facilities constructed by the transmission provider, not to existing facilities.

Commission Determination

361. The Commission denies rehearing of the decision to apply the modified test for credits only to transmission facilities added subsequent to the effective date of Order No. 890. In light of the new planning and coordination required in Order No. 890, it is appropriate to apply the new test on a prospective basis.[137] Existing facilities, by definition, have been developed without the benefit of the planning-related reforms adopted in Order No. 890 and, therefore, are not similarly situated to new facilities developed after the effectiveness of Order No. 890. As a result, only a network customer's new facilities will be subject to the presumption of integration standard. Similarly, the existing presumption applied to the transmission provider's facilities will continue to allow it to include in its rate base from the outset all network facilities constructed to meet its obligations to its customers, provided the presumption is not rebutted.

d. Cost of Customer Facilities Automatically Included in Transmission Provider Cost of Service Without a Rate Filing

362. Noting that automatic recovery of the costs of credits would be contrary to the Commission's long-standing policy concerning single-issue rate adjustments, the Commission declined to generically allow automatic recovery of the costs of credits associated with integrated transmission facilities to the transmission provider's cost of service. The Commission explained that transmission providers continue to have

[133] As we discuss in section III.B, planning activities must be open to all customers, who must provide information regarding expected uses of the system so that the transmission provider can plan for their needs.

[134] *See East Texas Electric Coop., Inc.* v. *Central and South West Services, Inc.*, 114 FERC ¶ 61,027 (2006).

[135] *E.g.*, APPA, East Texas Cooperatives, FMPA, NRECA, TAPS and TDU Systems.

[136] TAPS also cites *Tennessee Gas Pipeline Co.*, 104 FERC ¶ 61,063 (2003), *order on reh'g*, 108 FERC ¶ 61,177 (2004), *order on reh'g*, 110 FERC ¶ 61,385 (2005) for the proposition that new policies can be implemented for existing contracts.

[137] Order No. 890 at P 758.

the option to propose an automatic adjustment clause in their rates under FPA section 205 to address the time lag between incurring costs associated with credits and the transmission provider's next rate case.

Requests for Rehearing and Clarification

363. Florida Power requests that the Commission grant rehearing of the decision that customer credits do not warrant an exception to the Commission's general policy regarding single-issue rate adjustments. Florida Power argues that a transmission provider should not be required to dedicate the extensive resources required by a full-blown rate case to recover costs that, in its view, it has been forced to incur by the Commission's policy and over which it has no control.

364. E.ON U.S. requests that the Commission clarify that payment of credits is dependent on the transmission provider's ability to recover the costs of the credits. E.ON U.S. asks that the Commission adopt one of the following requirements: if the network customer's facilities are to be eligible for credits, the network customer must petition the Commission for a declaratory order stating that the transmission provider will be able to recover costs for the credits in the transmission provider's next rate case; the transmission provider need not provide the network customer with credits for its facilities until the costs of the credits are approved in the transmission provider's next rate case; or if the cost of the credits are rejected in the transmission provider's next rate case, the network customer is required to refund any amounts collected through the transmission credits, plus interest.

365. APPA asks that the Commission clarify that, if a transmission provider denies credits for network customer owned facilities, the transmission provider has a corresponding obligation to take steps to strip the costs of similar transmission facilities out of its own transmission revenue requirement where comparability requires such a result. TAPS argues that nothing in Order No. 890 altered the transmission provider's existing obligation to remove from its rate base transmission provider facilities comparable to those for which it denies credits to network customers.

Commission Determination

366. The Commission affirms its decision in Order No. 890 not to generically allow automatic rate recovery of the costs of credits associated with integrated transmission facilities to the transmission provider's cost of service. As explained in Order No. 890, automatic recovery would be contrary to our long-standing policy concerning single-issue rate adjustments, and transmission providers continue to have the option to propose an automatic adjustment clause in their rates under FPA section 205 to address the time lag between incurring costs associated with credits and the transmission provider's next rate case.[138] Since transmission providers may choose to add an automatic adjustment clause to their rates to address any lag in cost recovery, we reject as unnecessary the alternative proposals offered by E.ON U.S.

367. As for APPA's argument regarding the transmission provider's obligation to remove nonintegrated facilities from its revenue requirement, as explained above, the denial of credits for a network customer will no longer trigger an examination of the transmission provider's own facilities. Rather, the presumption of integration shall be rebuttable for transmission providers and customers alike. If it becomes apparent that the transmission provider has included facilities in its revenue requirement that are ineligible, such as when the transmission provider relies on its own facilities to demonstrate the lack of integration for customer-owned facilities, the network customer or the Commission, as appropriate, may initiate a complaint proceeding to have such facilities removed from rates.

e. RTO and ISO Issues

368. The Commission concluded in Order No. 890 that it would not be appropriate to generically exempt all RTOs and ISOs from the revised requirements regarding credits for network transmission customers. The Commission stated that it would address issues relating to network transmission customer credits in the RTO and ISO context in orders addressing OATT reform compliance filings submitted by each RTO and ISO. The Commission noted its prior determination that the existing tariffs of certain RTOs and ISOs provide opportunities for transmission customers to receive credit or the equivalent (*e.g.*, Transmission Congestion Contracts, Firm Transmission Rights or Auction Revenue Rights) for building facilities or upgrades that are consistent with or superior to Order No. 888 requirements.[139] The Commission explained that each RTO and ISO would have the opportunity to show on compliance that this continues to be the case given the reforms adopted in Order No. 890.

369. The Commission also addressed a request by NRECA to prohibit RTOs and ISOs from using a non-public utility's transmission facilities without compensating the entity because it is not a member of the RTO/ISO. The Commission found that there is not enough evidence on the record to make a generic determination on that issue. The Commission instead concluded it would be appropriate to address such issues on a case-by-case basis in response to appropriate filings under FPA sections 205 and 206.

Requests for Rehearing and/or Clarification

370. TAPS is concerned that Order No. 890 suggests that RTOs/ISOs can justify an exemption from OATT section 30.9 by claiming that firm transmission rights or similar mechanisms are the "equivalent" of credits under section 30.9. TAPS states that the RTO/ISO tariff provisions referred to by the Commission relate only to upgrades, which are funded by a customer but owned by a transmission owner, for a new service request or generator interconnection. TAPS therefore requests clarification that the rules with respect to whether a network customer funding facilities owned by a transmission owner should receive firm transmission rights in lieu of credits are unrelated to, and should not be confused with, the requirement in OATT section 30.9 that a network customer must be compensated for customer-owned facilities in a manner comparable to transmission owners.

371. NRECA reiterates its argument that the Commission should require RTOs/ISOs to compensate non-jurisdictional entities for use of the non-jurisdictional entities' transmission facilities as required by the principle of comparability. NRECA argues that the issue is purely legal and that no additional evidence is necessary, since NRECA is not seeking a ruling that a particular entity is entitled to compensation. NRECA states that the Commission's reliance on a "case-by-case" approach will be illusory if the Commission dismisses a complaint by a non-jurisdictional utility on the ground that the Commission has no jurisdiction over the non-jurisdictional entity's rates

[138] *See id.* at P 766.

[139] *See id.* at P 773, n.447.

under sections 205 and 206 of the FPA, as it did in *Central Iowa Power Coop.*[140]

Commission Determination

372. It was not the Commission's intention in Order No. 890 to prejudge whether Transmission Congestion Contracts, Firm Transmission Rights or Auction Revenue Rights should be treated as equivalents to the credits available under section 30.9 of the pro forma OATT. The Commission simply noted that those mechanisms exist and that the Commission would determine, as it evaluated compliance filings from individual ISOs and RTOs, whether such mechanisms served the same purpose and goal of section 30.9 and, in turn, should be considered proper substitutes for network customer credits. To the extent TAPS or others object to proposals made by a particular RTO or ISO, the appropriate forum to address those concerns is in the relevant compliance docket.

373. In response to NRECA, we continue to believe that it is appropriate to consider on a case-by-case basis customer claims that RTOs or ISOs are using the transmission facilities of a non-public utility without compensation. It would not be appropriate to address this issue in a vacuum, without a complete discussion by interested parties of the legal and policy merits of both sides of this issue.

3. Capacity Reassignment

a. Removal of the Price Cap

374. The Commission concluded in Order No. 890 that it is appropriate to lift the price cap for all transmission customers reassigning point-to-point transmission capacity, *i.e.*, resellers. The Commission found that the price cap had served to reduce transmission options for customers and impair the development of a secondary market for transmission capacity. The Commission concluded that removing the price cap will allow capacity to be allocated to those entities that value it the most, thereby sending more accurate price signals for identification of the appropriate location for construction of new transmission facilities to reduce congestion.

375. To enhance oversight and monitoring by the Commission of the secondary market for transmission capacity, certain reforms were adopted to the underlying rules governing capacity reassignments. First, the Commission required that all sales or assignments of capacity be conducted through, or otherwise posted on, the transmission provider's OASIS on or before the date the reassigned service commences. Second, the Commission required that assignees of transmission capacity execute a service agreement with the transmission provider prior to the date on which the reassigned service commences. Third, in addition to existing OASIS posting requirements, the Commission required transmission providers to aggregate and summarize in an electric quarterly report (EQR) the data contained in the service agreements for reassigned capacity. The Commission explained that, taken together, these reforms will increase the transparency of capacity reassignments and facilitate our monitoring of the secondary market for transmission capacity.

Requests for Rehearing and Clarification

376. Several petitioners request rehearing of the decision to lift the price cap on reassigned capacity.[141] Some petitioners question the Commission's stated justifications for the removal of the price cap. TDU Systems contend that the non-cost factors cited by the Commission, including promotion of the secondary market, enabling customers to better manage the risk of their long term commitments required by the reform of rollover rights, and sending more accurate price signals for capacity, do not justify lifting the price cap or substitute for analyzing the potential for the exercise of market power before lifting it. TDU Systems, APPA, and NRECA challenge the Commission's conclusion that removing the price cap for capacity reassignments will stimulate greater infrastructure investment by sending more accurate price signals as to the incremental cost of transmission capacity. They argue that explicit congestion price signals in RTO markets have failed to stimulate investment and, in any event, are useless for transmission customers that lack the regulatory certainty required to facilitate third-party construction of new facilities. APPA argues that entrenched economic interests often find it more profitable to pocket the remaining dollars than to invest in new facilities.

377. These petitioners all disagree with the Commission's finding that the price cap has impaired the development of a secondary market for transmission. They argue that the Commission cites no support for this finding and that it failed to address comments in response to the NOPR stating that non-price limitations on capacity reassignment, such as the requirement that the assignee use the same source and sink as original customers, are the real reason that reassignments of capacity do not occur. APPA also contends that the Commission failed to explain why the lifting of the price cap is necessary to spur investment in light of other reforms adopted in Order No. 890, such as a more robust transmission planning process and the provision of planning redispatch and conditional firm point-to-point service.

378. TAPS argues that the precedent relied upon by the Commission in Order No. 890 does not support the decision to lift the price cap for reassigned capacity. TAPS states that, in *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*,[142] the Commission actually required a market power analysis to justify market-based rates. TAPS argues that in *Interstate Nat'l Gas Ass'n of America* v. *FERC*,[143] the D.C. Circuit relied on empirical evidence to affirm the Commission's decision to lift the cap on gas pipeline capacity releases. In that case, TAPS argues that: there was a significant amount of firm capacity going unused, suggesting that excess capacity could constrain prices and with evidence that it did in fact put a downward pressure on prices; evidence existed that new entry could restrain prices; and, the price cap at issue was lifted only for two years during an experiment. TAPS argues that similar empirical evidence is required, showing that prices for secondary transmission capacity above the cap would be competitive and that new entry could constrain prices.

379. Petitioners generally argue that removal of the price cap may expose transmission customers to market power and is therefore contrary to Commission and judicial precedent. APPA and TAPS argue that the Supreme Court has rejected seller claims justifying higher prices for electricity based upon the value ascribed to the product by the buyer, stating that a "focus on the willingness to pay or ability of the purchaser to pay for a service is the concern of a monopolist, not a government agency charged both with assuring the industry a fair return and with assuring the public reliable and efficient service, at a reasonable

[140] *Central Iowa Power Coop.* v. *Midwest ISO*, 110 FERC ¶ 61,093, *order on reh'g,* 113 FERC ¶ 61,116 (2005).

[141] *See, e.g.*, APPA, NRECA, and TDU Systems.

[142] 74 FERC ¶ 61,076, *reh'g denied*, 75 FERC ¶ 61,024 (1996), *petitions for review denied sub. nom. Burlington Resources Oil & Gas Co.* v. *FERC*, 172 F.3d 918 (D.C. Cir. 1998).

[143] 285 F.3d 18 (D.C. Cir. 2002) (*INGAA*).

price.'' [144] In their view, this precedent requires the Commission to maintain the price cap in the absence of hard evidence of a competitive market for reassigned capacity.

380. Joined by NRECA and TDU Systems, APPA and TAPS argue that the Commission is allowed to authorize market-based rates only with empirical proof that existing competition would ensure that the actual price is just and reasonable and that undocumented reliance on market forces will not suffice.[145] In their view, the Commission must engage in an ex ante competitive analysis to find that the seller lacks market power, or take sufficient steps to mitigate market power, as well as adopt sufficient post-approval reporting requirements.[146] These petitioners argue that the Commission's reliance on competition among resellers, continued rate regulation of primary capacity, and the reassignment-related reforms adopted in Order No. 890 is insufficient to justify lifting the cap.

381. With regard to competition among resellers, APPA contends that transmission capacity is a scarce commodity and demand is currently inelastic, due in part to substantial load growth. APPA argues that allowing point-to-point customers to make virtually unlimited profits from reassignments of their firm service will not further competition among resellers and, instead, may discourage participation in joint planning to support expansion or acceptance of increased rates to support new facilities. APPA acknowledges that firm transmission not scheduled will be released on a non-firm basis, but argues that is of little use to LSEs in need of firm transmission to deliver their firm power supplies.

382. NRECA and TDU Systems argue that it is contradictory for the Commission to conclude that competition among resellers will assure just and reasonable prices when, elsewhere in Order No. 890, the Commission acknowledges congestion and the number of curtailments has dramatically increased in recent years. These petitioners question what market forces would constrain prices for secondary capacity at or below the price of primary capacity if primary capacity is so scarce. They question how it can be just and reasonable to price secondary rights at a level higher than the just and reasonable price of primary capacity. TAPS argues that a market power study of particular transmission paths is necessary to support a finding that competition among resellers will restrict market power.

383. With regard to the availability of primary capacity at cost-based rates, TAPS argues that the Commission has presented no factual basis to conclude that entry will be timely, likely or sufficient to defeat price increases due to transmission market power. TAPS contends that, where capacity is fully subscribed, non-existent capacity cannot act as a price restraint. APPA argues that any requirement for the transmission provider to build new facilities in future years has little if any bearing on the price an LSE is willing to pay for the next day, week or month to ensure it meets its service obligation. NRECA and TDU Systems contend that, notwithstanding the planning-related reforms of Order No. 890, transmission providers can continue to exert market power by refusing to expand the system to meet competitors' needs. TDU Systems contends that failure to mandate expansion of the grid or to encourage third party construction of needed upgrades will ensure a lack of expansion, allowing the holder of rights to transmission capacity to exert monopoly power in a secondary market unprotected by price caps.

384. Petitioners maintain that the revised oversight and reporting requirements adopted in Order No. 890 are insufficient to protect transmission customers from the exercise of market power. APPA and NRECA argue that post hoc reporting cannot prevent real-time harm to transmission customers and the end-users they serve or relieve the Commission of the obligation to ensure, at the outset, that the secondary market for capacity is competitive. TDU Systems similarly contend that the new posting and reporting requirements are unlikely to restrain the exercise of market power, since monthly reports will lag significantly behind the daily and hourly market transactions, even though greater price transparency may make market power easier to detect after the fact.

385. MISO argues that, instead of relying on continued regulation in the primary market and competition in the secondary market to limit the exercise of market power in the secondary market, the Commission should provide for a sharing mechanism between the reseller and the owner of the transmission asset to allocate any market premium obtained from the resale. MISO contends that revenue sharing would reduce incentives to engage in hoarding on the part of the reseller and encourage efficient use of the grid. In its view, sharing market premiums would have a solid ground in equity, ensuring that the owners of transmission, constrained by cost-based rates, are not unduly discriminated against in favor of the reseller.

386. APPA also contends that the use of value-of-service pricing for firm transmission service that LSEs require to meet their loads' needs violates FPA section 217(b)(4) because it does not enable the LSEs to secure the firm transmission rights they need to serve their loads as Congress intended. While not specifically opposing the Commission's decision to lift the price cap on reassignments of transmission capacity, South Carolina E&G makes a similar request that removal of the price cap be subject to the Commission's assurances that the resulting increased use of the grid will not compromise service to native load customers. In its view, an active secondary market could crowd the limits of the grid and increase the likelihood of curtailments. Southern Carolina E&G argues that FPA section 217 requires that native load service not be marginalized a result of any increased use of the grid.

387. If the Commission declines to reinstate the price cap on assignments of transmission capacity, TAPS asks that the Commission take two steps to offer consumer protection. First, TAPS asks the Commission to require utilities seeking to reassign transmission capacity to demonstrate a lack of transmission market power. TAPS argues that this demonstration should examine each point of receipt/point of delivery pair as a distinct market, unless the public utility can show that alternative paths provide meaningful substitutes. Second, TAPS asks the Commission to lift the price cap only for short-term services and only for a period of two years. TAPS suggests that, at the end of this period, the Commission should assess whether prices for reassigned capacity are competitive and whether the experiment produced the desired increase in reassigned capacity.

Commission Determination

388. The Commission affirms the decision in Order No. 890 to remove the price cap on reassignments of transmission capacity. We continue to believe that removal of the price cap will give market participants additional options for acquiring transmission. Point-to-point transmission service

[144] *Quoting Gainesville Utilities Department, et al.* v. *Florida Power Corp.*, 402 U.S. 515, 528 (1971).

[145] *Citing Farmers Union Cent. Exch., Inc.* v. *FERC*, 734 F.2d 1486 (D.C. Cir. 1984) (*Farmers Union*) (finding that the Commission failed to justify relaxation of cost-based regulation of oil pipeline companies because it did not ensure rates would remain within the zone of reasonableness).

[146] *Citing California ex. rel. Lockyer*, 383 F.3d 1006 (9th Cir. 2004) (*Lockyer*).

customers will have increased incentives to resell their service whenever others place a higher value on it. Existing transmission therefore will be put to better, more efficient use. Point-to-point customers also may be willing to commit to buy additional transmission service (such as for periods long enough to get rollover rights) since they are able to resell above the price cap during periods in which they do not need the capacity. On this basis alone, we find that establishing a competitive market for secondary transmission capacity will send more accurate signals that promote efficient use of the transmission system by fostering the reassignment of unused capacity.

389. We agree with petitioners that restricting reassignment to the same point of receipt and point of delivery has limited, and may continue to limit, the number of reassignments that take place. It does not follow, however, that the price cap is irrelevant or that lifting the cap will not encourage additional reassignments of transmission capacity. Petitioners acknowledge that the secondary market for transmission capacity is underdeveloped. Even if the price cap is not the sole cause for this lack of development, it is at least a contributing factor. While other reforms adopted in Order No. 890 also will facilitate use of and investment in the transmission system, this does not mean that lifting the price cap on capacity reassignments is unnecessary or unimportant. The reforms adopted in Order No. 890, including the decision to lift the price cap, work together to enhance customer options and the transmission provider's operation of the grid.

390. We are sensitive, however, to the concerns expressed by petitioners and grant rehearing to limit the period during which reassignments may occur above the cap. In Order No. 890, the Commission directed staff to closely monitor the quarterly reassignment-related data submitted by transmission providers to identify any problems in the development of the secondary market and to prepare a report on staff's findings for the Commission within 6 months of the receipt of two years worth of data, *i.e.*, by May 1, 2010. Upon further consideration, we conclude that it is most appropriate to lift the price cap on reassignments of capacity only to accommodate this study period and amend section 23.1 of the *pro forma* OATT to reinstate the price cap as of October 1, 2010. Upon review of the staff report and any feedback from the industry, the Commission can determine whether it is appropriate to continue to allow reassignments of capacity above the price cap beyond that date.

391. We disagree that a market power study or other empirical competition analyses are required to lift the price cap on capacity reassignments during this study period. Contrary to petitioners' assertions, market power analyses are not the only method to ensure that market-based rates remain just and reasonable.[147] In *INGAA*,[148] the court affirmed the Commission's removal of price ceilings for short-term capacity releasing shippers in the natural gas market without requiring sellers to submit market power analyses, recognizing non-cost factors such as the need to lift price ceilings to facilitate movement of capacity into the hands of those who value it most. The court concluded that these non-cost factors, combined with the limitation of negotiated rates to the secondary market, distinguished the case from *Farmers Union*.[149] Similarly, continuing rate regulation of the transmission provider's primary capacity, competition among resellers, and reforms to the secondary market for transmission capacity, combined with enforcement proceedings, audits, and other regulatory controls, will assure that prices in the secondary market for transmission capacity remain within a zone of reasonableness.[150]

392. Petitioners inappropriately discount the importance of these regulatory protections, particularly the continued rate regulation of primary transmission capacity. Unlike gas pipelines, transmission providers are obligated to construct new facilities to satisfy a request for service if that request cannot be satisfied using existing capacity. The *pro forma* OATT does not, and will not, permit the withholding of transmission capacity by the transmission provider and effectively establishes a price ceiling for long-term reassignments at the transmission provider's cost of expanding its system. Petitioner arguments to the contrary assume non-compliance with the transmission provider's obligations under the *pro forma* OATT. If a customer has evidence of such non-compliance, it should bring the matter to the Commission's attention through a complaint or other appropriate procedural mechanism. Absent such evidence, the Commission concludes that the continued rate regulation of the primary market, and the transmission provider's obligation to expand its system to accommodate service requests, adequately mitigates any market power that resellers may have in the long-term secondary market.

393. Pending the completion of upgrades, we acknowledge that delays associated with constructing new facilities could limit the downward effect that the transmission provider's cost of expansion has on prices. Resellers could attempt to gain market power through economic or physical withholding of their primary capacity when congestion arises. As the Commission found in Order No. 890, however, competition among resellers, as well as the ability of customers desiring additional capacity to access primary capacity using conditional firm point-to-point service or the modified planning redispatch implemented in Order No. 890, will mitigate the exercise of market power in the interim.[151] Moreover, any primary capacity that is not scheduled is made available to other customers on a non-firm basis, frustrating any attempts to withhold capacity.[152]

394. Reforms to the rules governing reassignments and associated reporting obligations also increase our regulatory oversight of the secondary market, allowing the Commission to effectively monitor that market for any attempts to exercise market power. All reassignments must now be conducted through or otherwise posted on OASIS and assignees must execute service agreements prior to the date on which service commences. Transmission providers must provide information regarding reassignments in their EQRs.[153] As noted above, Commission staff will also closely monitor the

[147] *See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076 at 61,227–36 (1996). The Commission ultimately determined in that case that a market power analysis was required in order to allow a pipeline to use market-based pricing instead of cost-of-service rates. The Commission has not proposed to allow transmission providers to engage in sales of primary capacity at market based rates and, as explained below, sufficient protections exist to ensure the secondary market for transmission capacity remains sufficiently competitive without requiring market power analyses from each reseller.

[148] 285 F.3d at 33.

[149] *INGAA*, 285 F.3d at 31–34.

[150] *See* Order No. 890 at P 811.

[151] *See* Order No. 890 at P 809, 812.

[152] *See id.* at P 811.

[153] As TDU Systems point out, the reports will lag behind the daily and hourly transactions in the market. As explained above, competition among resellers and regulatory protections embedded in the *pro forma* OATT will ensure that prices remain within the zone of reasonableness in the immediate near-term. The reports will enable the Commission to identify trends in the market and inefficiencies that may occur. Furthermore, if parties see that particular holders of transmission capacity are attempting to exercise market power through hoarding or other tactics, they can report such instances to the Office of Enforcement for investigation without delay.

quarterly reassignment-related data submitted by transmission providers and prepare a report on staff's findings for the Commission's consideration. The Commission takes seriously the possibility that resellers may attempt to exercise market power in the secondary market for transmission capacity. We continue to believe, however, that the regulatory protections in place and our increased oversight of this market will limit the potential for market power abuse during the period in which the price cap is lifted. There is no need for particularized market power studies regarding secondary transmission capacity, as suggested by TAPS.

395. We disagree with NRECA and TDU Systems that the potential for secondary prices to rise above primary capacity prices indicates that rates may not be just and reasonable. As the courts have recognized, prices in a competitive market should rise during periods when capacity is truly scarce in order to ensure that capacity is being allocated appropriately.[154] The precedent cited by petitioners clearly permits the Commission to implement alternative pricing structures provided that safeguards are in place to ensure that rates remain within a zone of reasonableness.[155] We continue to believe that the regulatory framework governing the reassignment of transmission capacity, combined with our increased oversight and enforcement authority, will ensure that the rates for secondary transmission capacity remain within the zone of reasonableness. At the same time, lifting the price cap will give primary transmission customers greater incentives to commit to long-term service because they will be able to resell above the cap during periods when they do not need the capacity.

396. We decline to adopt a mechanism to share revenues from capacity reassignments with the transmission provider. Allocation of the entire reassignment premium to the reseller is appropriate because it promotes an efficient allocation of transmission capacity, while sharing of the premium could make a potential seller less likely to resell even though another customer places a higher value on the transmission service. The Commission addressed a similar request in Order No. 636–A and concluded that releasing shippers in the gas market should be entitled to receive the proceeds from reselling their capacity.[156] Notwithstanding differences in the secondary market for transmission capacity, we believe that a similar approach should be followed for transmission providers, particularly since they already receive their full cost-of-service through payments for the underlying primary capacity. In any event, it would only be fair to share premiums with the transmission provider if losses were also shared when capacity was resold for less than the cost to the reseller of the capacity. Such sharing could lead to under-recovery of costs contrary to the premise of cost-of-service rates.

397. Finally, we do not believe that assignments will impose risks upon native load customers in contravention of FPA section 217 by increasing the likelihood of curtailments. Transmission providers should be planning the operation of their system to accommodate all reserved uses. Simply reassigning primary capacity from one customer to another should not alter the transmission provider's ability to satisfy its service commitments. We also disagree that lifting the price cap on reassignments of capacity will make it more difficult for LSEs to obtain firm capacity to serve their load or otherwise marginalize native load service, as APPA suggests. Lifting the price cap should encourage primary capacity holders to make more, not less, transmission available to other customers, including LSEs. While it is true that secondary capacity may at times be more expensive than primary capacity, establishing a competitive market for secondary transmission capacity will benefit all customers, including LSEs, by sending more accurate signals that promote efficient allocation of transmission capacity.

b. Lifting the Price Cap for Merchant Function and Affiliates

398. The Commission declined in Order No. 890 to adopt the NOPR proposal to retain price caps for capacity resold by a transmission provider's merchant function or its affiliates. After reviewing the comments submitted in response to the NOPR, and further considering its experience regulating capacity reassignments, the Commission concluded that retaining price caps for this portion of the market would continue to impair development of the secondary market and that price caps for such capacity are not otherwise necessary to ensure just and reasonable rates. The Commission found that there are no significant market power concerns to justify retaining the price caps for any transmission customer, noting that the Commission did not distinguish between affiliated and non-affiliated transmission customers when the Commission initially found in Order Nos. 888 and 888–A that excess capacity reserved could be reassigned.

Requests for Rehearing and Clarification

399. The same petitioners challenging the Commission's decision to lift the price cap for reassignments of capacity object specifically to lifting the price cap for reassignments by the transmission provider and its affiliates. APPA argues that this decision will result in more limited primary capacity, since it will be in the economic interest of the transmission provider's corporate family for the merchant function and/or affiliates of the transmission provider to buy any primary capacity that is available. APPA contends that such transactions would technically satisfy the transmission provider's obligation to make primary capacity available to customers, but effectively convert primary capacity into secondary capacity not subject to a price cap. APPA acknowledges that the Commission found in Order No. 890 that the Standards of Conduct will mitigate the ability of an affiliate to hoard capacity, but argues that the Commission failed to explain how such mitigation would occur.

400. TAPS expresses similar concern that the transmission provider will have an incentive to sell primary capacity to its merchant function or affiliates to get around the rate ceiling on primary capacity. If the secondary market is clearing at rates above the transmission provider's rate ceiling, TAPS argues that the parent corporation will have the incentive to put as much capacity in the hands of its merchant function or affiliates as possible, reducing the amount of price-restraining primary capacity and producing higher revenues for the parent corporation for sales of monopoly transmission service. In TAPS' view, costs associated with hoarding will not encourage resale if withholding profitably raises prices in the secondary market. TAPS also argues that the Commission's decision is

[154] *See INGAA*, 285 F.3d at 18, 32 (''[B]rief spikes in moments of extreme exigency are completely consistent with competition, reflecting scarcity rather than monopoly * * * A surge in the price of candles during a power outage is no evidence of monopoly in the candle market.'').

[155] *See Farmers Union*, 734 F.2d at 1509–10; *INGAA*, 285 F.3d at 32–34; *Lockyer*, 383 F.3d at 10–13; *see also Environmental Action* v. *FERC*, 996 F.2d 401, 410 (D.C. Cir. 1993).

[156] *See Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural gas Pipelines After Partial Wellhead Decontrol,* Order No. 636–A, 57 FR 36128 (August 12, 1992) FERC Stats. & Regs., Regulations Preambles January 1991–June 1996 ¶ 30,950 at 30,562 (1992) (''Since the pipeline is not releasing the capacity, no efficiency or other pro-competitive goal would be furthered by allowing it to retain incremental proceeds.'').

inconsistent with its conclusion elsewhere in Order No. 890 that transmission providers have an incentive to over-designate CBM, which TAPS states is a form of hoarding. TAPS complains that, although the Commission stated in Order No. 890 that it will monitor for hoarding behavior by transmission providers and their affiliates, it proposed no remedy in the event they engage in this behavior.

401. APPA, TAPS and TDU Systems argue that lifting the price cap for the transmission provider's merchant function and affiliate sales also will discourage transmission providers from constructing transmission capacity in an attempt to raise prices in the secondary market. They contend that corporate families profiting more from transmission capacity resold by its merchant function or unregulated affiliates will have a disincentive to build new transmission that would lower those resale prices. APPA argues that much of Order No. 890 is devoted to attempting to ensure that transmission providers do not discriminate in order to favor their own generation, yet lifting the resale cap for the transmission provider's merchant function and affiliates gives transmission providers incentives to favor their own and their affiliates' sale of reassigned capacity at unregulated rates and to limit construction of new transmission facilities and upgrades to keep the rates for such reassignments high. NRECA and TDU Systems agree, arguing that shareholders and senior management will be indifferent as to whether the profits are from primary or secondary markets, or from transmission or generation, and will seek to drive profits to monopoly levels if possible. TDU Systems argue that the fact that both affiliated and non-affiliated transmission customers were permitted in Order No. 888 to engage in reassignments of capacity is irrelevant because the ability to reassign capacity invoked few market power concerns so long as the price cap remained.

402. APPA also requests clarification as to whether the transmission capacity that a transmission provider's merchant function uses to serve the transmission provider's own retail loads is eligible for reassignment. If so, APPA argues that it is unduly discriminatory to deny network customers the ability to reassign their capacity. APPA contends that network service was developed specifically to provide to other LSEs a transmission service comparable to the transmission service that public utilities provide themselves.

Commission Determination

403. The Commission affirms the decision in Order No. 890 to lift the price cap for capacity resold by any point-to-point transmission customer, including the transmission provider's merchant function and its affiliates. We continue to believe that retaining the price cap for this portion of the market would impair development of the secondary market and is not otherwise necessary to ensure just and reasonable rates. In light of the protections discussed above, we find there are not significant market power concerns that would justify retaining resale price caps for any transmission customer.

404. While it is true that lifting the price cap for reassignments of capacity could provide an economic incentive for the transmission provider's merchant function or its affiliates to acquire transmission capacity in an attempt to exercise market power, the same is true for any customer. Under the Standards of Conduct, affiliated and unaffiliated customers have equal access to transmission-related information and, through the OASIS, equal opportunity to acquire primary transmission capacity. Thus, any customer could engage in speculative purchasing in an attempt to gain market power. The Commission found in Order No. 890 that the entire secondary market is now sufficiently competitive, in light of the reforms adopted, market forces, and other considerations, to justify lifting the price cap for all transmission customers reselling capacity.[157] As we explain above, there are sufficient structural and regulatory protections to ensure that no holder of capacity is able to exercise market power, regardless of whether the customer is affiliated with the transmission provider. The transmission provider must offer all firm (including long-term conditional firm) and non-firm capacity that is available and award that capacity in a non-discriminatory manner, which will undermine any customer's attempt to exercise market power. It therefore would not be appropriate to distinguish between classes of customers when lifting the price cap for reassignments.

405. We disagree that our decision will lead to lower investment in new facilities by transmission providers. The *pro forma* OATT places an affirmative obligation on transmission providers to expand their system in order to accommodate requests for service. In addition, Order No. 890 requires transmission providers to establish an open and transparent planning process to ensure that transmission plans are developed on a non-discriminatory basis. Transmission providers are also required to file reports with the Commission if they are late processing requests for new service and pay penalties if they are consistently late with service request studies. We conclude that these protections are adequate to ensure that transmission providers do not forego upgrades in an attempt to increase the value of capacity that has been assigned to their affiliates.

406. Because the Commission has found the secondary market for transmission capacity to be sufficiently competitive, it would not be appropriate to distinguish between classes of customers reselling their capacity. As we state above, however, the Commission takes seriously allegations of market abuse and we reiterate our intent to be vigilant in overseeing this market. If the Commission finds evidence of market abuse, we will exercise our enhanced authority by restricting the ability of an offending reseller (and possibly its affiliates) to participate in the secondary market for transmission capacity or imposing other remedies, including civil penalties, as appropriate. Should any customer believe that capacity is being preferentially allocated to a transmission provider's affiliates, that particular holders of transmission capacity are attempting to exercise market power through hoarding or other tactics, or that the transmission provider is failing to meet its expansion obligations, the customer should bring the matter to the Commission's attention through a complaint or other appropriate procedural mechanism. We direct staff to include in its report any evidence of abuse in the secondary market for transmission capacity.

407. With regard to APPA's request for clarification regarding the ability of the transmission provider's merchant function to reassign transmission capacity used to serve the transmission provider's retail load, we reiterate that only point-to-point transmission customers may reassign their transmission capacity.[158] To the extent the transmission provider's merchant function or a network customer has acquired point-to-point transmission, either may resell that capacity in the secondary market.

[157] *See* Order No. 890 at P 809. There the Commission distinguished its decision from the determination in Order Nos. 888 and 888–A to implement the price cap on all reassignments based on a finding that the entire secondary market was not sufficiently competitive to justify market-based pricing.

[158] *See* Order No. 890 at P 825.

c. Contracting and Posting Issues

408. As noted above, the Commission required in Order No. 890 that all sales or assignments of capacity be conducted through or otherwise posted on the transmission provider's OASIS on or before the date the reassignment commences. The Commission thus eliminated the ability of transmission customers to assign transmission rights to another party with subsequent notification to the transmission provider. The Commission also directed transmission providers, working through NAESB, to develop appropriate OASIS functionality to allow such postings. Transmission providers were not required to implement this new OASIS functionality or any related business practices until NAESB develops appropriate standards.

409. The Commission also required that assignees of transmission capacity execute a service agreement prior to the date on which the reassigned service commences. Transmission customers with market-based rate tariffs were no longer permitted to execute and implement assignments of capacity without involving the transmission provider, subject to after-the-fact reporting and posting. The Commission explained that this effectively returns the specified capacity to the transmission provider for the purpose of reassignment to the assignee and eliminates the need for the assigning party to have a rate schedule governing reassigned capacity on file with the Commission. The transmission provider's OATT will govern the reassigned service, with the assignee paying the transmission provider for service at the negotiated rate and the transmission provider billing or crediting the reseller with any difference between the negotiated rate and the reseller's original rate. All the non-rate terms and conditions that otherwise would apply to the transmission provider's sale of transmission capacity continue to apply in the case of a reassignment.

410. In addition to already existing OASIS posting requirements, the Commission required transmission providers to aggregate and summarize in an EQR the data contained in the service agreements for reassigned capacity. The Commission directed that the quarterly report be submitted in the EQR so that it is readily accessible to the Commission and the public. The Commission also revised section 23 of the *pro forma* OATT to address reassignments of transmission capacity and added a *pro forma* service agreement for reassignments in a new Attachment A–1.

Requests for Rehearing and Clarification

411. Several petitioners request rehearing and clarification of the requirement that there must be a service agreement in place between the transmission provider and the assignee prior to the assignment commencing. Bonneville argues that requiring transmission providers to execute service agreements with assignees is too onerous and that it is unnecessary for the Commission to monitor more closely the secondary market for transmission capacity. Bonneville further argues that it would be virtually impossible to execute a service agreement for daily or hourly reassignments, harming the market for reassignments of short-term transmission. Bonneville also suggests that requiring a written contract for assignments may cause OASIS transactions between a reseller and assignee to be non-binding and force the transmission provider to maintain two systems for transactions, one electronic and one for paper transactions.

412. Bonneville also contends that if an assignee fails to return an executed service agreement under the Commission's new rules, transmission service could not commence even though the reseller and assignee concluded an assignment on OASIS. Bonneville claims that, under the Commission's OASIS standards, the transmission provider has no ability to invalidate, refuse, decline, retract or annul an assignment on OASIS and, therefore, no ability to recall the assigned capacity from the assignee and return it to the reseller. Bonneville states that OASIS would show the reservation in the name of the assignee and the assignee would be able to schedule transmission without a service agreement, effectively nullifying the requirement.

413. Joined by EEI, Bonneville suggests that the Commission clarify that the requirement to execute a service agreement with the assignee is satisfied by a previously executed umbrella agreement between the transmission provider and the assignee and that the execution of a service agreement covering a particular assignment is not required. EEI contends that this would be consistent with the current requirement for customers taking short-term firm and non-firm service under the *pro forma* OATT. EEI requests clarification that, regardless of whether the assignee has executed a service agreement with the transmission provider, the same OASIS posting requirements would apply to reassignments as apply to any reservation of transmission service. EEI argues that an assignee should be required to inform the transmission provider through an OASIS posting of the terms and conditions of the assignment so that the transmission provider and other customers are informed of the existence of a reservation for transmission capacity.

414. Constellation argues that there is no basis in the record for the Commission to adopt formal assignment procedures for short-term reassignments. Constellation asks that the Commission grant rehearing to allow short-term and temporary assignments of transmission capacity to occur without a formal reassignment of the transmission service agreement. Constellation suggests that the Commission consider other means of separating the filing requirements for capacity reassignment from those for market-based rates tariffs, such as by establishing standardized tariff terms in its regulations and authorizing entities, upon notice to the Commission, to adopt those regulations as their filed tariff for reassignments.

415. Several petitioners object to the billing mechanism adopted for capacity reassignments. Bonneville argues that transmission providers should be allowed to continue billing the reseller for the assigned capacity. Bonneville contends that requiring transmission providers to bill at the negotiated rate will insert the transmission provider into the financial arrangements of the reseller and the assignee, obligating the transmission provider to monitor the parties' business arrangements and adjust its own operations to compensate. Bonneville also contends that transmission providers are not set up to charge assignees rates that are different from the normal transmission rate. If a robust assignment market develops, Bonneville states that transmission providers could have to charge dozens of different rates varying from day to day or even hour to hour. Bonneville suggests that both the reseller and assignee would likely be purchasing other transmission in addition to the assigned capacity, requiring the transmission provider to charge at least two different rates to the same customer. Bonneville contends that significant changes will have to be made to all transmission providers' billing systems at substantial cost to the industry to accommodate the Commission's reform of the rules governing capacity reassignment.

416. EEI and Southern suggest that transmission providers be required to charge the assignee at the same rate that

the reseller originally agreed to pay and allow the reseller and assignee to arrange for any difference between the original price and the negotiated reassignment price. Southern argues that requiring the transmission provider to act as settlement agent unnecessarily complicates and duplicates the transmission provider's burdens and responsibilities, noting the Commission declined to impose such an obligation when third party generators provide planning redispatch.[159] EEI argues that the service agreement with the reseller terminates when the assignee executes a new service agreement and, as a result, the transmission provider has no contractual basis to collect revenues from the reseller if the reseller has resold its capacity at a price lower than the price it agreed to pay the transmission provider.[160] Joined by Washington IOUs, EEI suggests that requiring the transmission provider to charge the assignee at a rate different from the price stated in its OATT would violate either the discount rule or the ceiling price. If the Commission declines to change its billing rules on rehearing, EEI requests that Schedules 7 and 8 of the *pro forma* OATT be amended to provide that ceiling prices and discounting rules do not apply in the context of reassigned transmission capacity.

417. EEI contends that the Commission's concerns with respect to the reporting of the price of reassigned capacity can be addressed without requiring the transmission provider to become involved in the payment stream related to the reassignment. EEI argues that all jurisdictional resellers of transmission report those transactions in their EQRs. If the Commission wants all capacity reassignments on a system to be in a single report, EEI argues it can require the assignee to inform the transmission provider of the price and other terms of service and the transmission provider can include this information in its EQR.

418. Washington IOUs distinguish between long-term and short-term reassignments, arguing that different rules should be adopted for each type of transaction. For long-term reassignments, Washington IOUs argue that transmission providers should only be required to take on a bilateral relationship with an assignee where all rates, terms and conditions of the assignment are the same as the original rates, terms and conditions of the purchase of primary capacity. Otherwise, they contend the transmission provider may be unable to recover the rate owed to it in the event of a dispute between the reseller and assignee. For short-term reassignments, they argue the transmission provider should continue to bill the reseller for the assigned capacity scheduling rights, with the assignee paying the reseller directly. Washington IOUs contend that NAESB distinguishes between long-term and short-term reassignment transactions, which they argue is appropriate to ensure transmission providers are not unduly burdened by being forced to act as a middleman between resellers and assignees.

419. TranServ contends that the NAESB standards distinguish between resales of scheduling rights and transfers of all obligations, including financial responsibilities. TranServ states that, under the NAESB standards, a resale does not alter the financial obligation for the capacity reassigned, which remains with the reseller. TranServ argues that the billing mechanism adopted in Order No. 890 inappropriately shifts this financial obligation to the assignee, unduly burdening the transmission provider with the responsibility to manage settlement of the reassignment.

420. EEI asks the Commission to refer to NAESB the issue of whether any modifications to the OASIS protocols are required to implement the modifications to transmission reassignments required in Order No. 890. EEI requests that NAESB be directed to report to the Commission on whether modifications are required to implement transmission reassignments being posted before-the-fact rather than after-the-fact and if so, NAESB's estimated timeline for development of such modifications.

421. Several petitioners complain about the cost to the transmission provider of providing the accounting and billing for capacity reassignments. EEI and Washington IOUs contend that the Commission's billing rules require the transmission provider to subsidize the administrative costs of the reassignment by collecting and distributing payments on behalf of the reseller and assignee. Washington IOUs argue that the transmission provider's limited resources would be better used in areas more central to the transmission provider's core responsibilities. MidAmerican asks that the Commission expressly limit the ability of assignees to further assign capacity, arguing that the administrative tracking and posting of additional reassignments would be costly. To the extent the Commission requires transmission providers to continue to credit and charge revenues from reassignments of capacity, E.ON U.S. and TranServ ask the Commission to clarify that transmission providers should be compensated for the accounting services they provide to act as billing agents for reassignments of capacity. Unless a compensation mechanism is spelled out in the *pro forma* OATT, these petitioners argue that the financial obligations between the reseller and assignee should remain with those parties.

Commission Determination

422. The Commission affirms the decision in Order No. 890 to require assignees to execute a service agreement with the transmission provider governing reassignments of transmission capacity prior to scheduling use of that capacity. We provide clarification of this requirement, however, in response to the concerns raised by petitioners. In Order No. 890, the Commission required that all reassignments be accomplished by the assignee executing a service agreement with the transmission provider that will govern the provision of reassigned service.[161] The Commission did not intend to impose contracting obligations that are more onerous than the acquisition of primary transmission capacity, which may be accomplished through execution of a service agreement followed by scheduling on OASIS. We clarify that it is equally sufficient for an assignee to execute a service agreement governing its reassignments of capacity generally and to complete a particular assignment through the OASIS. However, as with reservations of primary transmission capacity, there remains a threshold requirement to execute a service agreement with the transmission provider in order to commit the assignee to abide by the terms and conditions of the transmission provider's OATT governing the reassignment of transmission service.

423. It would not be appropriate to relieve assignees of the obligation to execute a service agreement with the transmission provider since such agreements establish the necessary contractual relationship between the assignee and the transmission provider. As we explain above, sales of reassigned capacity now take place under the transmission provider's OATT and, thus, there must be a contractual relationship between these parties. This does not mean, however, that all of the

[159] *Citing* Order No. 890 at P 1160.

[160] *Citing id.* at P 816, n.496.

[161] *See id.* at P 816. The Commission adopted corresponding revisions to section 23.1 of the *pro forma* OATT requiring the execution of a service agreement prior to the date on which the reassigned service commences that will govern the provision of reassigned service.

terms and conditions of a particular assignment must be stated in the service agreement. Like short-term firm and non-firm reservations of primary capacity, the transmission provider and assignee may rely on OASIS to provide information regarding the reseller, quantity, and price associated with a particular reassignment of service. This information would then become part of the binding agreement between the transmission provider and assignee governing the assignment,[162] just as confirmation of short-term firm and non-firm transactions on OASIS constitute binding contractual commitments. Because execution of a service agreement with the transmission provider governing reassignments of capacity is a threshold requirement for an assignee wishing to accomplish a particular reassignment on OASIS, Bonneville's concern regarding the failure of an assignee to return its service agreement is misplaced. The assignee in that instance would have no right to schedule a reassignment on OASIS since it has not first executed the appropriate service agreement with the transmission provider.

424. Some of the confusion regarding these contracting requirements may have been caused by the Commission's reference in section 23.1 of the revised *pro forma* OATT to a service agreement ''that will govern the provision of reassigned service,'' which could be interpreted to refer to transaction-by-transaction service agreements for reassignments. Inclusion of the words ''Long-Term Firm'' in both the title of the form of service agreement and the attached specifications in the new Attachment A–1 to the *pro forma* OATT adopted in Order No. 890 may have added to the confusion by potentially implying that use of the service agreement is limited to long-term firm point-to-point transactions instead of also applying to short-term firm point-to-point and non-firm point-to-point reassignments, as intended by the Commission.[163] We revise section 23.1 of the *pro forma* OATT and the title of Attachment A–1 to make clear that use of the form of service agreement for reassigned capacity, and associated posting of schedules and transaction information on OASIS, should be similar to the use of such agreements for primary capacity.[164]

425. The execution of a service agreement by the assignee does not itself terminate the reseller's service agreement, as EEI argues. The reseller's service agreement remains in place, granting the reseller scheduling rights for the reserved capacity and obligating the reseller to pay for that reservation. During the term of the assignment, the reseller will continue to be billed under its agreement with the transmission provider. The assignment of service simply transfers to the assignee some or all of the reseller's scheduling rights for the period of the reassignment and, in return, obligates the assignee to pay the transmission provider the negotiated rate. In order to prevent over-recovery by the transmission provider, the transmission provider must therefore credit the reseller the reassignment rate, which leaves the reseller with the net difference between the resale rate and the reseller's original rate.[165] If the assignee defaults and fails to pay for the reassigned capacity, the transmission provider should reverse the credit to the reseller to reflect the lack of payment by the assignee.[166]

426. We disagree that these billing requirements are unduly burdensome. While it is true that the transmission provider may be required to bill at different rates, that is already the case under the *pro forma* OATT. Transmission providers are permitted to offer discounts from the rates stated in their OATT, provided they offer such discounts to all eligible customers. Offering discounts thus creates different rates for different customers depending on when they negotiate service. The transmission provider therefore should already have mechanisms in place to bill customers based on rates other than those stated in its OATT. In any event, the need to bill assignees directly for reassignments is inextricably linked to the decision to require that all reassignment transactions take place pursuant to the rate on file in the transmission provider's OATT, rather than bilateral agreements between customers.[167] We therefore do not intend for the discount rule or the price ceilings otherwise stated in the transmission provider's OATT to apply to reassignments of capacity. We have revised schedules 7 and 8 of the *pro forma* OATT accordingly.

427. We clarify that, to the extent necessary, the costs incurred by the transmission provider to account and bill for reassignments of transmission capacity should be included in the transmission provider's cost of service, just like accounting and billing costs for any other service under the transmission provider's OATT. We decline MidAmerican's request to prohibit further assignments of reassigned capacity. Order No. 888 allowed for multiple reassignments under the *pro forma* OATT and MidAmerican does not justify departing from this practice. Just as the original transmission customer may find that it has excess capacity it can reassign, so may an assignee. Denying the assignee's right to further assign its scheduling rights would inhibit customers who value the capacity most from accessing it and thereby contradict the Commission goal of creating a competitive secondary market for transmission capacity.

428. With regard to OASIS modifications necessary to allow for the reassignment of transmission capacity, the Commission in Order No. 890 already directed transmission providers working through NAESB to develop appropriate OASIS functionality to allow for reassignment-related postings.[168] We understand that this work is on-going and expect any necessary modifications to NAESB's business practices that are necessary to reflect our rulings in this order will be adopted prior to the submission of those standards for Commission review. In the interim, transmission providers should identify in their business practices any

[162] The EQR for reassignments of transmission capacity must contain all relevant transaction data, whether stated in the service agreement or related OASIS schedule.

[163] *See pro forma* OATT Attachment A–1, Form of Service Agreement for the Resale, Reassignment or Transfer of Long-Term Firm Point-to-Point Transmission Service.

[164] As with the form of service agreement for firm point-to-point transmission service, we retain the specifications attachment for the form of service agreement governing reassignments. We understand that long-term agreements for reservations of primary capacity rely on the specifications attachment, so we would expect similar practices to be used regarding long-term reassignments of transmission capacity. As with any transaction, however, actual uses of primary and secondary capacity should be scheduled on OASIS consistent with applicable business procedures.

[165] If the reseller and assignee agree to a full transfer of the reseller's rights and obligations, the reseller would only make payments to the extent the transfer is executed at a lower rate than the rate agreed to between the reseller and transmission provider, to ensure that the transmission provider receives the full contract price agreed to by the reseller. If the full transfer is executed at a rate in excess of the reseller's contract with the transmission provider, the transmission provider must credit the reseller with the additional revenue as a result of the transfer.

[166] The transmission provider may take action against the assignee as it would any other default under the *pro forma* OATT. We recognize that, in this instance, the transmission provider may have little incentive to pursue collection since it will recover its original contract rate from the reseller, but it could transfer to the reseller its legal rights to enforce the assignee's payment obligations.

[167] It is therefore irrelevant that payments for third-party planning redispatch are settled bilaterally, since the underlying planning redispatch service is not provided under the transmission provider's OATT.

[168] *See* Order No. 890 at P 815.

procedures necessary to accomplish the reassignment of capacity by their customers.

d. Market-Based Rate Tariffs

429. Because purchasers of transmission capacity in the secondary market will execute a service agreement directly with the transmission provider, the Commission stated in Order No. 890 that there will no longer be a need for the assigning party to have on file with the Commission a rate schedule governing reassignment capacity. The Commission explained that the transmission provider's OATT will govern the reassigned service.

Request for Rehearing and Clarification

430. EPSA and Powerex question how sellers with market-based rates are to proceed regarding the removal of the price cap stated in their market-based rates tariffs. In order not to violate their market-based rate tariffs, these petitioners contend that sellers may be obligated to file revisions of their tariffs and receive an order approving those revisions prior to reselling transmission above the cap. Powerex also suggests that existing market-based rate tariffs require a seller of transmission capacity to continue reporting in its quarterly reports the name of an assignee. Powerex and EPSA request that the Commission deem void, as of the effective date of Order No. 890, the provisions in each individual seller's market-based rate tariffs that impose a cap on resale prices and reporting obligations. Petitioners suggest that these resellers be permitted to update their market-based rate tariffs at such time as the tariff is amended or with their next triennial update.

Commission Determination

431. In Order No. 890, the Commission explained that reassignments of transmission capacity will now be governed by the transmission provider's OATT.[169] Each assignee must execute a service agreement directly with the transmission provider, which we clarify above may be an umbrella service agreement governing multiple reassignment transactions scheduled on OASIS. As a result, the sale of reassigned capacity is made by the transmission provider pursuant to the terms and conditions of its OATT, not by the reseller under its market-based rate tariff. Although the reseller may negotiate the relevant price with the assignee, the reassignment itself is governed by the transmission provider's OATT. The reseller's market-based rate tariff is no longer relevant or controlling. The Commission therefore explained in Order No. 890 that the reseller does not need to have on file with the Commission a rate schedule governing reassigned capacity.

432. In Order No. 697, the Commission affirmed this approach, explaining that it is no longer appropriate to include in the market-based rate tariff transmission-related services.[170] The Commission stated that reassignments of capacity are, instead, provided for in the revised *pro forma* OATT and that capacity holders seeking to reassign transmission capacity should adhere to the provisions of Order No. 890. Because these reassignment-related provisions of the market-based rate tariff were no longer needed, the Commission directed sellers to revise their market-based rate tariffs to remove the provisions at the time they otherwise revise their tariffs to conform them to the standard provisions adopted in Order No. 697.[171]

433. To the extent confusion remains as to the relationship between the market-based tariff and the transmission provider's OATT, we reiterate that, as of the effective date of the reforms adopted in Order No. 890, all reassignments of capacity must take place under the terms and conditions of the transmission provider's OATT. To the extent a reseller has a market-based tariff on file, the provisions of that tariff, including a price cap or reporting obligations, will not apply to the reassignment since such transactions no longer take place pursuant to the authorization of that tariff. As the Commission directed in Order No. 697, sellers should amend their market-based rate tariff to remove provisions regarding the reassignment of capacity when they otherwise revise their tariffs to conform them to the standard provisions adopted in Order No. 697.

4. ''Operational'' Penalties

a. Unreserved Use Penalties

(1) Unreserved Use of Transmission Service and Inappropriate Use of Network Service

434. In order to eliminate a potential source of discretion in the implementation of the *pro forma* OATT and to enhance the Commission's enforcement of OATT obligations, the Commission clarified, in Order No. 890, the application of unreserved use penalties. The Commission determined that a transmission customer would be subject to unreserved use penalties in any circumstance where the transmission customer uses a transmission service that it has not reserved. Specifically, a transmission customer will be subject to an unreserved use penalty in circumstances where a transmission customer has a transmission reservation, but uses transmission service in excess of its reserved capacity. A transmission customer also will be subject to an unreserved use penalty if the transmission customer uses transmission service without the appropriate transmission reservation.

435. The Commission declined to exempt any class of customers from the potential assessment of unreserved use penalties, including LSEs serving native load in multiple control areas, and noted that the transmission provider itself is subject to the same penalties when it takes transmission service under its OATT. The Commission stated that a network customer or transmission provider that inappropriately uses network transmission service to support off-system sales may be required to disgorge unjust profits from such sales, as the Commission may determine on a case-by-case basis. The Commission stated that it would evaluate the appropriateness of civil penalties in addition to unreserved use penalties on a case-by-case basis. The Commission concluded that it is appropriate to subject both a network customer and transmission provider inappropriately using network transmission service to unreserved use penalties because such action potentially uses or acquires, without an appropriate reservation, transmission service that could be allocated to other customers. The Commission modified the language of section 30.4 of the *pro forma* OATT to clarify that network customers are subject to unreserved use penalties when they schedule delivery of off-system non-designated purchases using transmission capacity reserved for designated network resources.

436. The Commission clarified that a network customer may use the undesignated portion of a remote network resource to serve network load using secondary network service and may use the undesignated portion of the resource for other non-network service purposes, such as third-party sales, as long as the network customer acquires the appropriate point-to-point service. The Commission also noted that, because the transmission provider does not have to ''take service'' under its OATT for the transmission of power

[169] *See id.* at P 816, n.496.

[170] *See Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity and Ancillary Services By Public Utilities,* Order No. 697, 72 *FR* 39,904 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 (2007).

[171] *Id.* at P 920.

that is purchased on behalf of bundled retail customers, it is free to use the undesignated portion of a remote network resource to serve its bundled retail customers. The Commission affirmed that, if the transmission provider desires to use a remote network resource for non-native load purposes, such as third-party sales, it must acquire the appropriate point-to-point service.

437. In order to ensure that the transmission provider has a basis for charging an unreserved use penalty, the Commission modified section 13.4 of the *pro forma* OATT to provide that a customer that takes unreserved point-to-point transmission service and does not have a service agreement with the transmission provider is deemed to have executed the transmission provider's form of service agreement for point-to-point service. The Commission also clarified that a customer that uses more transmission service than it has reserved is also subject to charges for ancillary services based on the period of unreserved use. The Commission modified section 3 of the *pro forma* OATT to reflect that rule.

Requests for Rehearing and Clarification

438. AWEA seeks clarification of the Commission's statement that intermittent resources could avoid unreserved use penalties by reserving sufficient transmission capacity to deliver the resource's full output. AWEA asks that the Commission confirm that it did not intend to require resources to always reserve point-to-point transmission service based on the maximum potential output in order to avoid unreserved use penalties. AWEA contends that such a practice would be cost prohibitive for a wind generator, which often operates at less than full output, and could require multiple transmission reservations, up to full nameplate capacity, on multiple transmission paths for generators that market their output at multiple trading points from day to day. AWEA contends that determining whether a positive imbalance event results in an unauthorized use of transmission depends on whether the transmission provider is contractually obligated to deliver a resource's actual or full output, or only a fixed amount of power, and, to the extent the positive generation imbalance is physically delivered from point A to point B, whether such delivery is covered by a transmission service reservation.

439. If the Commission does not grant the requested clarification, AWEA requests rehearing to the extent Order No. 890 authorizes transmission providers to impose unreserved use penalties for every instance of positive generator imbalance. AWEA argues such a requirement would be inconsistent with the Commission's refusal to delineate the specific circumstances that constitute unreserved use of the transmission system. AWEA further argues that applying unreserved use penalties in every instance of positive generation imbalance would subject generators to duplicative charges for an imbalance and would render uneconomic substantial numbers of wind power transactions. AWEA argues such a policy would be unjust, unreasonable and unduly discriminatory against wind power generators that have no ability to control the actual output of their facilities.

440. TDU Systems argue that it is unjust and unreasonable for the Commission to subject LSEs to penalties for inadvertent uses of network service when managing loads and resources across a neighboring control area. TDU Systems contend that serving native load in multiple control areas requires managing resources across those boundaries and the flexibility to respond to changes in service requirements on a timely basis in a cost-efficient manner comparable to the way in which transmission providers use network service to manage their retail native load service obligations. In their view, inadvertent takes of transmission service in excess of reservations occur for reasons beyond the control of the LSE and, therefore, assessing unreserved use penalties is inappropriate. TDU Systems also object to the Commission's statement that it would not, as a general policy, exempt an LSE's unreserved use from potential civil penalties. TDU Systems argue that the imposition of civil penalties on LSEs that inadvertently violate the prohibition on unauthorized use would be unjust and unreasonable on its face. TDU Systems suggest that payment for the increment of service actually used but not reserved makes the transmission provider whole without visiting further penalties on behavior that is by definition unintentional.

441. TDU Systems argue that inadvertent takes of transmission service in excess of reservations by an LSE serving native load in multiple control areas should be treated as an energy imbalance in the control area in which the energy imbalance occurs, rather than as an unauthorized use of point-to-point service. TDU Systems object to the Commission's characterization of energy imbalance charges as compensation to the transmission provider for the additional expense it incurs to compensate for a transmission customer's failure to schedule sufficient energy to serve its load, arguing that imbalance charges contain a penal, above-cost component that make the transmission provider more than whole. In their view, the more onerous unreserved use charges should be reserved for intentional over-scheduling of transmission reservations.

442. In order to prevent inadvertent uses from occurring in the first place, TDU Systems contend that transmission providers should be required, as a condition of being able to impose penalties, to use software designed to identify unreserved uses. TDU Systems suggest that such software could disallow tags for service that exceeds reserved levels. They argue that the Commission missed the point by rejecting this suggestion in Order No. 890 based on the expectation that the reforms adopted would reduce the level of unreserved use penalties for instances of inadvertent uses. TDU Systems contend that the Commission's stated objective of discouraging disorderly use of the transmission system would be better achieved by requiring the use of software designed to identify inadvertent uses, rather than the assessment of steep unreserved use penalties.

443. TDU Systems further argue that prior Commission approval of penalties should have been required, arguing that due process requires nothing less than Commission notice, review, and approval, as well as an opportunity for a hearing, before application of any unreserved use penalty. TDU Systems argue that the burden should be on the transmission provider to justify any requested penalties, rather than on the transmission customer to disprove the reasonableness of a penalty through the complaint process.

444. TAPS requests clarification of the Commission's statement that the transmission provider is free to use the undesignated portion of a remote network resource to serve its bundled retail customers since it does not have to ''take service'' under its OATT for the transmission of power that is purchased on behalf of bundled retail customers. TAPS contends that, although a transmission provider is not required to take network service to meet the needs of its bundled retail loads, it does have to abide by all of the requirements of designating network resources for such purpose [172] and that the non-tariff

[172] *Citing pro forma* OATT section 28.2; *Wisconsin Public Power Inc. SYSTEM* v. *Wisconsin Public Svc. Corp.*, 84 FERC ¶ 61,120 (1998).

service the transmission provider uses for itself must be comparable to the network service provided to its transmission customers.[173] TAPS argues that the transmission provider's own use of non-designated resources (or portions of resources) to meet bundled retail therefore must be on a non-firm basis supported by secondary network service, as is the case for network customers.[174] TAPS requests rehearing to the extent the Commission intended to allow transmission providers preferential use of the transmission system.

445. TAPS also requests clarification that the Commission's discussion of secondary network service was intended to address only what a network customer (or the transmission provider) can and cannot do with respect to the host transmission provider's system and does not place any limitations on the use of resources on the remote systems. TAPS asks that the Commission clarify that the host transmission provider cannot impose a penalty for scheduling delivery of designated or undesignated portions of a customer's remote resources when such delivery does not utilize the host transmission provider's transmission system.

446. Washington IOUs contend that established rules in place since Order No. 888 have allowed network customers to use a firm transmission path reserved for a designated network resource for any power (including economy purchases) as long as the use did not exceed the amount of the firm network reservation. Washington IOUs argue that the Commission reversed this long-standing policy by prohibiting the use of a reserved firm path for network capacity to deliver power from a non-designated resource, which, in turn, improperly and unreasonably devalued network service in comparison to point-to-point service. Washington IOUs contend that whether the megawatts using the reserved transmission capacity are coming from a designated network resource or a replacement power source is largely irrelevant because this distinction does not affect grid use and causes no harm to any other customer so long as the quantity does not exceed the amount of the reservation. Washington IOUs state that the Commission places no restrictions on the resource used to provide the megawatts flowing over a capacity reserved in a long-term firm point-to-point reservation and that it would degrade the quality of network service to impose such restrictions, and associated penalties, on network customers. In their view, providing penalties for such uses of the transmission system would provide a windfall to other transmission customers because the circumstances giving rise to these penalties cause no harm to other customers.

Commission Determination

447. The Commission declines to distinguish between intentional and unintentional unreserved transmission uses and reiterates that all unreserved uses will be subject to operational penalties. We conclude that maintaining penalties for any unreserved use of transmission service will create the right incentives for customers to take appropriate measures to minimize any unreserved use before it occurs, whether intentional or not. As the Commission noted in Order No. 890, any unreserved use of transmission service can harm reliability and disrupt the allocation of transmission rights.[175] It is therefore appropriate to maintain penalties for both intentional and unintentional unreserved uses. The Commission was sensitive, however, to the concerns of commenters, determining in Order No. 890 that penalties should be based on the period of unreserved use rather than the period for which service is reserved, which could be much longer. This penalty structure more closely approximates the penalty charge with the impact on the transmission system while maintaining the correct incentive for transmission customers to take the necessary steps to ensure that they reserve appropriate service.

448. The Commission continues to believe that it would not be appropriate to exempt any class of customers from unreserved use penalties. While we appreciate that intermittent resources have limited ability to precisely forecast or control generation levels, they are able to reserve sufficient transmission capacity to deliver their full output in the event it is produced, thereby mitigating potential unreserved use penalties. In this regard, intermittent resources are no different than any other generator and, thus, application of unreserved use penalties is not discriminatory. Exempting these or any other type of resource from unreserved use penalties would diminish incentives to reserve adequate transmission to deliver the resource's output, potentially creating reliability problems for the transmission provider and discriminating in favor of the resource in the allocation of transmission rights.

449. The Commission also disagrees that imposing unreserved use penalties on generators for inadvertent positive generation imbalances is duplicative of imbalance charges that may be assessed. As the Commission explained in Order No. 890, imbalance charges and unreserved use penalties serve different purposes.[176] Imbalance charges result from a transmission customer's failure to schedule adequate capacity for energy deliveries, whereas unreserved use penalties result from a transmission customer's failure to reserve adequate capacity for energy deliveries. Even though a transmission customer may be assessed charges for both an imbalance and an unreserved use in a particular scenario, that is appropriate because the transmission customer has delivered energy in excess of what it reserved *and* scheduled. In that instance, application of an imbalance charge in addition to an unreserved use penalty recognizes that the transmission customer both failed to reserve adequate transmission as well as failed to properly schedule its energy deliveries.

450. We acknowledge, as TDU Systems argue, that imbalance charges contain a penalty, above-cost component, but disagree that this alone justifies relieving a customer of an unreserved use penalty. As a threshold matter, we note that revenues from imbalance charges or unreserved use penalties in excess of the transmission provider's costs or relevant transmission rate are distributed to transmission customers, not retained by the transmission provider. More to the point, however, imbalance charges and unreserved use penalties are associated with different actions and, as such, are designed to compensate the transmission provider for different things, while also providing appropriate incentives to transmission customers. We continue to believe that both imbalance charges and unreserved use penalties should apply to the extent the customer's reservation and schedule are insufficient.

451. We also acknowledge that, in certain circumstances, inadvertent unreserved uses by an LSE serving load in multiple control areas may be beyond the LSE's control at the moment they occur. This does not mean, however, that penalties should not apply to such unreserved uses. Like any customer, the LSE is able to protect itself against unreserved use penalties by reserving sufficient capacity. We also reject the argument that civil penalties would be unjust and unreasonable on their face if applied to inadvertent unreserved uses

[173] *Citing pro forma* OATT section 28.3.

[174] *Citing In re SCANA Corp.*, 118 FERC ¶ 61,028 (2007); *Idaho Power Co.*, 103 FERC ¶ 61,182 (2003).

[175] *See* Order No. 890 at P 838.

[176] *See id.* at P 837.

by an LSE. As with any civil penalties, the Commission will consider the facts and circumstances before it when determining whether to impose a civil penalty for unreserved use of transmission service.

452. As the Commission explained in Order No. 890, we will not require transmission providers to use software designed to identify unreserved uses as a condition of being able to impose operational penalties.[177] It is the obligation of the transmission customer, not the transmission provider, to ensure that the customer has reserved the transmission service that it uses. Moreover, we do not have sufficient evidence before us now to decide that, as a general matter, development and implementation of such software would be more appropriate than assessing penalties for inadvertent unreserved uses, which we note were significantly reduced by the reforms adopted in Order No. 890. For the same reasons expressed in Order No. 890, we reject TDU Systems' argument that Commission approval is required prior to assessing an unreserved use penalty.[178]

453. With regard to TAPS' concern about the transmission provider's use of the system to serve native load, Order No. 890 did not disturb the requirement from Order No. 888 that transmission providers serving native load must designate network resources and load. Although transmission providers are not required to take service under their OATT in such circumstances, we reiterate that, to the extent a transmission provider takes power from a non-designated network resource to serve bundled retail load, such power must be on a non-firm basis comparable to secondary network service.[179] To the extent necessary, the Commission clarifies that Order No. 890 was not intended to grant transmission providers greater flexibility than other network customers when using undesignated network resources or undesignated portions of designated network resources to serve bundled retail load.

454. We also clarify, as TAPS requests, that the Commission's discussion of secondary network service in Order No. 890 was intended to address only what a network customer (or the transmission provider) can and cannot do with respect to the host transmission provider's system.[180] The host transmission provider cannot impose a penalty for scheduling delivery of designated or undesignated portions of a customer's remote resources when such delivery does not utilize the host transmission provider's transmission system. Unreserved uses of the host transmission provider's system can, however, be charged an unreserved use penalty, and section 13.4 of the *pro forma* OATT provides that the customer using the unreserved service shall be deemed to have executed a service agreement with the host transmission provider to govern that service. To the extent necessary, we clarify that all unreserved uses of the host transmission provider's system are to be considered uses of firm point-to-point transmission service, even if the customer is taking network service or non-firm point-to-point service for the reserved portion of its service.

455. We disagree with Washington IOUs that a network customer's use of firm transmission capacity reserved for a designated network resource to deliver power from a non-designated resource causes no harm to other customers. The Commission has long required network customers to use secondary network service to deliver energy from non-designated resources to serve network load.[181] To allow network customers to use the firm transmission capacity reserved for designated network resources in such circumstances would unduly preference the network customer over other potential users of that firm capacity. In such a case, the transmission customer could avoid potential curtailments because the purchased energy is scheduled with a higher curtailment priority under NERC guidelines than it would receive had the transmission customer used secondary network or non-firm point-to-point transmission service.[182] In addition, the transmission customer uses service that would have potentially been unavailable if it had requested service as required.

(2) Penalty Rate for Unreserved Use of Transmission Service

456. The Commission determined in Order No. 890 that it will continue giving transmission providers discretion in setting their unreserved use penalty rates to the extent they are consistent with that order. If a transmission provider elects to charge unreserved use penalties, the Commission explained that such penalty charges must be based on the period of unreserved use rather than the period for which service is reserved, subject to certain principles. First, the unreserved use penalty for a single hour of unreserved use will be based on the rate for daily firm point-to-point service, even if the transmission provider has a rate for hourly firm point-to-point service on file. Second, as a general rule, more than one assessment for a given duration (*e.g.*, daily) will increase the penalty period to the next longest duration (*e.g.*, weekly).

457. The Commission affirmed the requirement that a transmission provider wishing to charge unreserved use penalties must explicitly state the penalty rate in its OATT. The Commission also retained the current policy established in *Allegheny Power Sys., Inc.* that the unreserved use penalty rate may not be greater than twice the firm point-to-point rate for the period of unreserved use.[183] The Commission established a rebuttable presumption that unreserved use penalties no greater than twice the firm point-to-point rate for the penalty period are just and reasonable. The Commission further stated that transmission providers proposing an unreserved use penalty in excess of twice the relevant firm point-to-point rate for pervasive unreserved use could do so in a filing under section 205 of the FPA. Transmission providers proposing such a rate must establish that a higher penalty rate is required to combat pervasive unreserved use of transmission and why the standard rate that penalizes repeated unreserved use is not adequate to discourage repeated instances of unreserved use of transmission service.

Requests for Rehearing and Clarification

458. TDU Systems contend that a 200 percent penalty rate is excessive and unnecessary to the extent it is based on periods greater than the unreserved use period. TDU Systems argue that, if system integrity and reliability are the bases upon which the penalty policy is founded, then penalties for a single hour should be based on the rate for hourly transmission service, and so forth. TDU Systems state that that they generally agree that a transmission customer must face a penalty in excess of the firm point-to-point rate in order to have an incentive to reserve the appropriate amount of service, but contend that the Commission fails to justify charging 200 percent penalties on periods greater than the unreserved use period. In their view, a 200 percent penalty might be

[177] *See id.* at P 835.

[178] *See id.* at P 836.

[179] *See*, *e.g.*, Order No. 888 at 31,745.

[180] *See* Order No. 890 at P 839.

[181] *See pro forma* OATT section 28.4; Order No. 888 at 31,748.

[182] *See MidAmerican Energy Co.*, 112 FERC ¶ 61,346 (2005); *PacifiCorp*, 118 FERC ¶ 61,026 (2007).

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

appropriate if based only on the period of unreserved use but is excessive and unnecessary when applied to periods greater than the unreserved use.

459. TDU Systems further contend that a 200 percent penalty is excessive in any event for an isolated inadvertent use. In their view, the Commission should limit any application of the 200 percent penalty charge to intentional or persistent, repeated unauthorized uses. TDU Systems claim that the Commission misconstrued this proposal in its comments on the NOPR. TDU Systems states that they do not argue that only repeated unreserved uses should be subject to a penalty. Rather, they argue that the 200 percent penalty in particular should apply only to intentional or persistent unauthorized uses.

460. E.ON U.S. maintains that the Commission failed to address whether, or how, a transmission provider may recover a penalty from customers whose unauthorized use of transmission service also includes unauthorized use of ancillary services. E.ON U.S. asks the Commission to clarify that ancillary service rates for unauthorized uses are subject to the same price cap (twice the applicable ancillary services rate for the period of unauthorized use) and pricing criteria that apply to the unauthorized transmission penalty rates. If not, E.ON U.S. contends that the charge for such unauthorized uses of ancillary services will not discourage unauthorized use of ancillary services.

Commission Determination

461. The Commission affirms the adoption of a rebuttable presumption that unreserved use penalties up to two times the transmission provider's applicable point-to-point service rate are just and reasonable. This penalty structure provides appropriate incentives to transmission customers to purchase the correct amount of transmission capacity, yet is not unduly harsh in light of changes to the definition of the penalty period. Prior to Order No. 890, transmission providers could assess unreserved use penalties based on the length of the transmission customer's reservation. The Commission reformed that practice in Order No. 890, significantly relaxing unreserved use penalties by requiring that they be based on the period of use.[184] The Commission balanced the penalty rate of 200 percent against that reform, and we continue to believe that the balance struck provides transmission customers a just and reasonable incentive to reserve the correct amount to transmission capacity.

462. It is therefore appropriate to apply the 200 percent penalty rate to all unreserved uses, whether inadvertent or intentional. As explained above, all unreserved uses have the potential to impair reliability and disrupt the allocation of transmission rights and, therefore, all should be subject to a penalty. Underlying TDU Systems' request for rehearing on this point is an apparent belief that persistent unauthorized uses should be subject to higher penalties to distinguish them from inadvertent uses. In response, we note that the penalty structure adopted in Order No. 890 already provides for increased penalties for persistent unreserved uses since more than one assessment for a given duration will increase the penalty period to the next longest duration. To the extent a transmission provider believes additional penalties are necessary to prevent pervasive unauthorized use, it may make a filing under FPA section 205 to propose such additional penalties.[185]

463. In response to E.ON U.S., the Commission clarifies that all charges for ancillary service costs associated with unreserved uses must be based on the actual costs of the ancillary service attributable to the unreserved use, *i.e.*, not subject to the 200 percent penalty rate. For example, a transmission customer with one hour of unreserved use may be charged for one hour of ancillary service costs associated with that use, even if the customer is charged twice the daily point-to-point rate for the underlying unreserved use. We believe the 200 percent penalty as applied to the firm point-to-point rate based on the period of unreserved use is an adequate incentive to accurately schedule without applying an additional penalty on the related ancillary service charge. If a transmission provider wishes to impose charges for ancillary services as a component of an unreserved use penalty, the transmission provider must expressly state so in its OATT.

b. Distribution of Operational Penalties

464. Consistent with its determination regarding the distribution of imbalance penalties, the Commission concluded in Order No. 890 that transmission providers must distribute all unreserved use and late study penalties they collect, whether from the transmission provider's merchant function or other transmission customers. The Commission required that unreserved use penalties be distributed to all non-offending transmission customers, whether or not affiliated with the transmission provider (including the transmission provider's native load) and required all late study penalties to be distributed to non-affiliates.

465. The Commission required the transmission provider to make an annual compliance filing and, in that filing, propose: (1) A mechanism to identify non-offending transmission customers; (2) a method to distribute the unreserved use penalty revenues it receives to the identified transmission customers; and (3) how it will distribute late study penalties to unaffiliated transmission customers. The Commission also required the transmission provider to make an annual filing that provides information regarding the penalty revenue the transmission provider has received and distributed.[186] The Commission declined to require the transmission provider to make an annual filing to propose a distribution method for unreserved use and late study penalties, concluding instead that the annual informational filing requirement was sufficient.

466. In order to make the transmission provider whole prior to distribution of unreserved use penalty revenues, the Commission allows the transmission provider to retain the base firm point-to-point transmission service charge and to distribute any revenue collected above the base firm point-to-point transmission service charge to all non-offending customers. The transmission provider is required to distribute the entire amount it pays under section 19.9 of the *pro forma* OATT for completing service request studies on an untimely basis. The Commission also prohibited

[184] *See* Order No. 890 at P 846. The Commission explained that penalty charges must be based on the period of unreserved use, subject to certain principles. First, the unreserved use penalty for a single hour of unreserved use will be based on the rate for daily firm point-to-point service, even if the transmission provider has a rate for hourly firm point-to-point transmission service on file. Second, as a general rule, more than one assessment for a given duration (*e.g.*, daily) will increase the penalty period to the next longest duration (*e.g.*, weekly). For example, a customer having two unreserved daily uses within a week could be charged an unreserved use penalty equal to the weekly firm point-to-point rate plus a penalty component up to 100 percent of that weekly firm point-to-point rate, for a total unreserved use penalty charge up to 200 percent of the point-to-point weekly rate.

[185] *See id.* at P 849.

[186] The annual informational filing must provide: (1) A summary of penalty revenue credits by transmission customer; (2) total penalty revenues collected from affiliates; (3) total penalty revenues collected from non-affiliates; (4) a description of the costs incurred as a result of the offending behavior; and (5) a summary of the portion of the unreserved penalty revenue retained by the transmission provider. *See* Order No. 890 at P 864.

transmission providers from recovering for ratemaking purposes or through any service under the Commission's jurisdiction any amount it or an affiliate pays as an operational penalty.

Requests for Rehearing and Clarification

467. TDU Systems argue that any retention of revenues from the unreserved use penalty by affiliated, non-offending transmission customers will dilute the impact of the penalty by returning some of it to the corporate family. While unaffiliated transmission customers pay 100 percent of the penalty, TDU Systems contend that affiliated transmission customers would pay less than the full operational penalty since some of the costs will be returned to the corporate family. TDU Systems claim that this discount constitutes undue discrimination and is inconsistent with comparability.

468. Claiming that it would be time-consuming and burdensome for a transmission provider to refile, on an annual basis, its methodology for assessing and distributing operational penalties, Ameren and EEI ask the Commission to clarify that the distribution methodology is to be proposed in a one-time compliance filing. In their view, the annual informational filing is more appropriately limited to implementation of the distribution methodology, *i.e.*, the amount of penalties assessed, the amounts distributed to customers, and the amounts retained by the transmission provider. Ameren and EEI suggest that any changes to the distribution methodology proposed after acceptance of the one-time compliance filing be submitted in a separate filing under FPA section 205. EEI also asks the Commission to clarify whether the one-time compliance filing proposing the transmission provider's distribution methodology is to be submitted when the transmission provider makes the other tariff modifications to comply with Order No. 890 or at some other date.

469. MidAmerican seeks a number of clarifications regarding the requirement to propose a distribution methodology in a compliance filing. MidAmerican asks the Commission to clarify that the transmission provider must wait for a Commission order before commencing the implementation of its filed revenue distribution plan. MidAmerican also questions whether it would be acceptable for a transmission provider to use the full annual compliance period to identify the non-offending transmission customers or, if not acceptable, whether the billing month should be used. MidAmerican suggests that an ''offending transmission customer'' should be classified as such for the entire reporting period and not for a subset of the reporting period. Finally, MidAmerican contends that it should be acceptable to allocate the penalty revenues between non-offending network customers and point-to-point customers based on the total megawatt-hours that each of these customer groups scheduled during the compliance period. If the Commission disagrees, MidAmerican seeks clarification of how to allocate the penalty revenues between the two customer groups. With regard to the annual informational filing, MidAmerican asks the Commission to confirm that it is acceptable to submit the annual informational filing some months following the compliance filing. MidAmerican also suggests that both the compliance filing and the informational filing can be submitted any time during a calendar year for penalties that were imposed during the prior calendar year.

470. MidAmerican requests further clarification that penalty revenue distribution should be treated as credits toward a future billing cycle. MidAmerican also suggests that the Commission adopt a reasonable threshold below which penalty revenue distributions become disproportionately burdensome, such as any calendar year when the total penalties are less than $10,000. Below that threshold, MidAmerican suggests that the transmission provider should have the option to make the payment to the transmission provider's regional reliability organization, which it states would contribute to reducing payments for reliability that benefits all customers.

Commission Determination

471. As some petitioners note, the discussion of the process for distributing operational penalties in Order No. 890 is somewhat unclear. We grant rehearing to explain more precisely the process transmission providers must follow in filing their unreserved use penalty rates, operational penalty distribution methodologies, and annual compliance reports with the Commission.

472. First, if a transmission provider elects to impose unreserved use penalties, it must submit to the Commission a tariff filing under FPA section 205 stating the applicable unreserved use penalty rate. Second, each transmission provider also must submit a one-time compliance filing under FPA section 206 proposing the transmission provider's methodology for distributing revenues from late study penalties and, if applicable, unreserved use penalties. This one-time compliance filing can be submitted at any time prior to the first distribution of operational penalties. Transmission providers should request an effective date for this distribution mechanism as of the date of the filing and may begin implementing the methodology immediately, subject to refund if the Commission alters the distribution mechanism on review. The distribution mechanism, as accepted by the Commission, will remain effective until the transmission provider files changes to the proposed structure or the Commission directs any such changes on its own motion. Finally, each transmission provider must report on its penalty assessments and distributions in an annual compliance report to be submitted on or before the deadline for submitting FERC Form-1, as established by the Commission's Office of Enforcement each year. This annual compliance report should be filed under in the same docket as the docket in which the proposed one-time compliance filing is submitted.

473. Although we will continue to allow transmission providers to propose a mechanism through which they will identify who is a ''non-offending'' transmission customer for purposes of making unreserved use penalty distributions, this should not be based on the entire calendar year, as MidAmerican suggests. For instance, for purposes of calculating penalty revenue distributions, it would not be appropriate for transmission providers to lump together all customers who caused any degree of unreserved use over the course of a year into one group and then distribute the penalty revenues to the remaining customers. We believe that it is best to consider the remaining details of a transmission provider's distribution mechanism, including the particular period used to identify non-offending customers (*e.g.*, quarterly, monthly, *etc.*), on a case-by-case basis on review of the one-time compliance filing proposing the distribution mechanism.

474. The Commission rejects requests for rehearing of the determination to allow revenues for unreserved use penalties to be distributed to all non-offending customers, including affiliates. We acknowledge that this may result in the transmission provider receiving penalty revenues on behalf of its native load even when its affiliate has been identified as offending customers, or vice versa. We nevertheless believe it is a more equitable and administratively efficient method for all users of the transmission system that are subject to unreserved use penalties to be eligible to receive a

portion of associated revenues. If the Commission were to distinguish between affiliates and non-affiliates in this instance, it would follow that transmission customers that are affiliated among themselves, but not with the transmission provider, should also be excluded from distributions to the extent one of the customers is offending. Given the complicated ownership structures prevalent in the electric industry, in which one company may own a small percentage of several companies, determining whether certain transmission customers are affiliates would be a time-consuming exercise for the transmission provider.

475. As the Commission stated in Order No. 890, we will require all operational penalty revenues to be distributed, with no exception. In the case of unreserved use penalties, we require penalty revenues to be distributed to non-offending customers and, in the case of late study penalties, we require penalty revenues to be distributed to all non-affiliates of the transmission provider. We will therefore deny MidAmerican's request to allow certain thresholds below which transmission providers may distribute penalty amounts to third parties such as regional reliability organizations. Such a policy could decrease the financial incentive built into the current rule, which rewards non-offending customers with a portion of the distributed revenues for abiding by Commission policies. We recognize, however, that it could be administratively difficult for some transmission providers to distribute small amounts of penalty revenues and note that transmission providers have flexibility in developing their distribution methodologies to minimize administrative burdens, by establishing reasonable minimum thresholds to trigger a distribution, provided they do not unduly restrict the distribution of penalty amounts.

c. Applicability of Operational Penalties Proposal to RTOs and Other Independent or Non-Profit Entities

476. The Commission clarified in Order No. 890 that RTOs and independent transmission coordinators, like any other transmission provider, are bound by the requirement to distribute revenues they receive when they assess operational penalties. The Commission declined to exempt non-profit transmission providers from the requirement to distribute unreserved use penalties they pay to the extent they take service under their own tariffs. If a non-profit transmission provider incurs an operational penalty as a result of its activities as a transmission customer, it is required to distribute penalties to non-offending customers.

Requests for Rehearing and Clarification

477. Ameren asks the Commission to clarify that non-profit transmission providers, including RTOs, are not liable for any operational penalties. If a penalty is assessed on an RTO or non-profit transmission provider, Ameren contends they should not be allowed to flow through to their ratepayers the costs of such penalties, regardless of whether their affiliates engage in for-profit activities. Ameren contends that allowing for such recovery would be inconsistent with Commission policy.[187] With respect to RTOs in particular, Ameren contends that allowing RTOs to pass through penalties essentially punishes companies for participation in an RTO. To the extent a non-profit transmission provider is assessed an operational penalty at all, Ameren contends it should only be obligated to pay such penalty to the extent it can do so through any operations in which the transmission provider retains any proceeds above its costs, such as wholesale marketing operations of the transmission provider or its affiliates. If the Commission wishes to sanction an RTO, ISO, or independent system administrator, Ameren argues that it should consider different measures, such as reductions in management bonuses.

478. New York Transmission Owners agree that penalties must be structured so they do not flow through to other parties and similarly suggest that penalties be paid through items like variable pay or bonus programs. With respect to potential penalties paid by NYISO, New York Transmission Owners ask the Commission to require that they be paid out of compensation and incentive programs and that the Commission tailor such penalties to recognize NYISO's limited ability to pay them.

479. NYISO and the ISO/RTO Council, however, object to disallowance of cost recovery for operational penalties. They state that the Commission neither generically allowed nor disallowed pass-throughs of reliability-related penalty costs in Order No. 672 and, instead, adopted a case-by-case approach, inviting RTOs and ISOs to make filings under FPA section 205 to propose penalty cost recovery mechanisms. They argue that the Commission failed to identify any difference between reliability and operational penalties that would justify departing from the case-by-case approach adopted in Order No. 672.

480. The ISO/RTO Council argues that use of variable employee bonus funds to pay operational penalties would penalize employees for issues beyond their control and impair the ability to hire and retain qualified management. It contends the Commission would have no authority under FPA section 316A to impose penalties on particular employees for tariff violations of their employer utility. The ISO/RTO Council objects to potential personal liability as a violation of due process and an attempt to dictate the internal management decisions of a public utility.

481. NYISO contends that the prohibition on recovering penalty costs in rates is inconsistent with the Commission's Policy Statement on Enforcement,[188] which provides that the level of penalties should account for the effect on the financial viability of the company that committed the wrongdoing and reasonably reflect the seriousness of an offense. NYISO acknowledges that the Commission indicated it would consider financial impacts on RTOs and ISOs when deciding whether to assess penalties, but argues the Commission erred in assuming that non-profit RTOs and ISOs can somehow absorb penalty costs.

482. NYISO states that the premise underlying the Commission's decision in Order No. 890 that RTOs and ISOs have other sources of revenue that could absorb penalty costs is flatly incorrect. NYISO explains that it collects revenues for both transmission and non-transmission services (*i.e.*, market administration) through Rate Schedule 1 and that all revenues from sources other than Rate Schedule 1 (*e.g.*, interconnection studies, customer trainings, and interest earnings) are used to reduce Rate Schedule 1 charges. NYISO therefore contends that it has no excess funds available to pay penalties. NYISO states that it does interpret Order No. 890 to allow it to recover penalty costs through any rates and thus questions how a non-profit RTO and ISO could recover those costs. NYISO asks the Commission to grant rehearing and allow non-profit RTOs/ISOs to argue, on a case-by-case basis, for an opportunity to recover penalty costs or to explain why sanctions other than financial penalties should be imposed.

483. National Grid agrees that the Commission should consider the unique problems associated with the non-profit

[187] *Citing* Order No. 890 at P 865; *Cleco Corp.*, 104 FERC ¶ 61,125 at 61,441 (2003).

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

status of RTOs/ISOs in determining the type and treatment of penalties applicable to such entities. Absent extraordinary circumstances that warrant a monetary penalty for RTOs/ISOs, National Grid argues the Commission should use non-monetary penalties in the first instance to address violations by the RTO or ISO. To the extent that penalties are imposed, National Grid contends that the RTO or ISO should be authorized to pass the costs of such penalties to its customers and that these customers, in turn should be authorized to recover the costs of such penalties from their own customers.

Commission Determination

484. The Commission denies rehearing of the decision in Order No. 890 not to categorically exempt any class of transmission providers from the potential imposition of operational penalties. As we explain in section III.D.4.a., competing internal policies or staffing issues could lead an RTO or ISO to treat particular types of requests differently notwithstanding their organizational independence from market participants. By imposing late study penalties on RTOs and ISOs, the Commission has established financial incentives for those transmission providers to complete request studies in a timely manner or otherwise justify their inability to do so. RTOs and ISOs are like any other transmission provider in this regard. We will nonetheless take into consideration the relative ability of non-profit transmission providers to pay late study penalties on review of their notification filings, consistent with the Enforcement Policy Statement.[189]

485. We acknowledge, as NYISO points out, that non-profit transmission providers may not have sources of revenue from which they can absorb late study penalties other than revenues collected under a Commission-jurisdictional tariff. As we explain in section III.D.4.a., the intent of prohibiting transmission providers from automatically passing on to customers the costs of late study penalties was to preclude those transmission providers from designing their rates to accommodate a pass through of the penalties, *i.e.*, effectively including penalties in its cost of service. The 60-day due diligence standard is in place to protect customers and it would therefore be inappropriate to automatically recover from those customers penalties assessed for non-compliance. An RTO or ISO is permitted to use revenues previously collected under Commission-approved rates to pay late study penalties by reallocating funds as necessary to distribute late study penalty amounts. This does not mean, as the ISO/RTO Council implies, that the Commission is imposing personal liability on employees for penalties applied to an RTO or ISO. Each RTO and ISO has discretion to determine, as an organization, how to reallocate its funds.

486. We decline to state generically which particular sources of funds should be used to pay late study penalties, since that question would best be answered on a case-by-case basis. If the RTO or ISO is unable to identify any appropriate funds from which to pay a late study penalty, the Commission will consider case-specific cost-recovery proposals under FPA section 205, provided they do not allow for automatic pass-through of penalties applied to the RTO or ISO.

5. ''Higher of'' Pricing Policy

487. In Order No. 890, the Commission did not address proposals to change or clarify the ''higher of'' pricing policy and, instead, addressed only the narrow issue of whether changes to the *pro forma* OATT are necessary to ensure that, consistent with the ''higher of'' policy, incremental cost transmission rates are presented as monthly rates for service.[190] Rather than quoting incremental costs as monthly rates, the Commission noted that some transmission providers had been quoting incremental rates as lump sum payments, a practice that is inconsistent with our ratemaking policy. In Order No. 890, the Commission concluded that changes to the *pro forma* OATT are not needed to address this matter. The Commission explained that the transmission provider must continue to include a proposed monthly incremental rate with its offer of service whenever it proposes to charge the customer an incremental rate. The transmission provider must also provide cost support for the derivation of the rate consistent with the cost support that the transmission provider would provide to the Commission in a section 205 rate filing.

Requests for Rehearing and Clarification

488. EEI requests clarification that transmission providers may calculate the incremental costs of network upgrades so as to allow incremental rates to vary over the term of the contract to reflect changes in the transmission provider's cost of service. While recognizing that the Commission declined to grant this clarification in Order No. 890, EEI believes that this clarification will enhance compliance with the Commission's policies and is therefore within the scope of this proceeding.

489. Great Northern seeks rehearing of the Commission's decision not to require transmission providers to permit a customer to opt for a longer contract term (to obtain a longer amortization period and a lower rate) once the incremental cost of transmission upgrades has been determined. Great Northern argues that failure to grant this option will result in uncertainty and delay in the development of competitive generation resources. Great Northern claims that there is no record evidence that adopting its request would be problematic for any transmission provider, customer, or market participant. Great Northern contends that, if an increase in contract term would trigger a need for additional, or different, upgrades, it would be the responsibility of the transmission customer to pay for those upgrades over the term of the contract.

490. If the Commission does not allow general flexibility for transmission customers to adjust the term of their requested transmission service contract to provide a longer period for amortizing the costs of system upgrades once the incremental cost of expansion is disclosed by the transmission provider, Great Northern requests the Commission to allow contracts to be extended in the specific circumstances where pending transmission service requests were made for one year (or longer if necessary to pay for any required system upgrades) and the transmission provider is on notice of the potential need for a longer contract term. Great Northern states that it has made twenty-three transmission service requests on transmission provider systems which are currently being studied, and in each instance the request was made for a one year term or longer if necessary to pay for any required system upgrades.

[189] *See* Policy Statement on Enforcement at P 20 (indicating that assessment of penalties should take account of the financial viability of the offender).

[190] Order No. 890 at P 884. In Order No. 888, the Commission stated that system expansions should be priced at the higher of the embedded cost rate (including the expansion costs) or the incremental cost rate, consistent with the Transmission Pricing Policy Statement. *See Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act,* Policy Statement, 59 FR 55031 at 55037 (Nov. 3, 1994), FERC Stats. & Regs. ¶ 31,005 at 31,146 (1994), *order on reconsideration,* 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

Commission Determination

491. We continue to believe that the specific pricing proposal suggested by EEI is outside the scope of this proceeding, as the NOPR and Order No. 890 addressed only the narrow issue of whether changes to the *pro forma* OATT are necessary to ensure that incremental cost transmission rates are presented as monthly rates for service. As the Commission explained in Order No. 890, such issues are best addressed on a case-by-case basis in particular rate proceedings. We note, however, that the capital costs of upgrades, as estimated in a facilities study, and eventually specified in a service agreement through an incremental rate, are not subject to change once the customer has executed the service agreement. It would not be appropriate to vary capital costs over the term of such contracts.

492. Great Northern presents no new arguments or information on rehearing that cause us to revisit the decision not to require the transmission provider to permit the customer to opt for a longer contract term once the incremental cost of the upgrades has been determined. The Commission explained in Order No. 890 that the specific upgrades required to provide the requested transmission service may depend on the time period over which the service is provided. Allowing the customer to opt for a longer contract term may therefore trigger a need for additional, or different, upgrades. If this were to happen, there would be disruption of the study process and costs could increase.

493. Additionally, such changes could undermine the fundamental first-come, first-served aspect of long-term transmission service. Order No. 888 provided for long-term firm point-to-point transmission service on a first-come, first-served basis.[191] Lengthening the term of a contract once the incremental costs of upgrades is determined would be a material change to the original transmission service request, voiding the original request and creating a new request. Allowing a customer to lengthen its contract term as Great Northern suggests could allow the transmission customer to supersede another eligible customer's first-in-time claim to future transmission service in violation of Order No. 888. The fact that the transmission customer would be responsible for paying for any additional upgrades, or the possibility that development of competitive generation could be delayed, does not address the potential uncertainty and chaos that could arise from undermining the first-come, first-served foundation of long-term point-to-point transmission service. We therefore deny rehearing on this issue.

[191] *See pro forma* OATT section 13.2.

6. Other Ancillary Services

a. Demand Response

494. The Commission affirmed in Order No. 890 the existing *pro forma* OATT provision that transmission customers may purchase from third parties, or make alternative comparable arrangements for the provision of all ancillary services except for scheduling, system control and dispatch service, and reactive supply and voltage control service. Regarding the sale of other ancillary services, the Commission clarified that the sale of such services by load resources should be permitted where appropriate on a comparable basis to service provided by generation resources. The Commission modified Schedules 2, 3, 4, 5, 6, and 9 of the *pro forma* OATT to make clear that reactive supply and voltage control, regulation and frequency response, energy imbalance, spinning reserves, supplemental reserves and generator imbalance services, respectively, may be provided by non-generation resources such as demand resources where appropriate.

Requests for Rehearing and Clarification

495. E.ON U.S. asks the Commission to clarify on rehearing that, for purposes of providing reactive supply and voltage control service, non-generation resources only include dynamic resources. Without such a clarification, E.ON U.S. contends that capacitors added in big blocks could claim to be resources capable of providing reactive power, even though such resources only supply VARS and would need to be properly sized and located in order to provide effective reactive capability. E.ON U.S. also argues that "non-generation sources" must be a controllable resource, *i.e.*, a resource that a transmission provider can connect to via an automatic signal, to be followed automatically and immediately by the resource within a time period that is useful for providing reactive power.

496. E.ON U.S. requests further clarification that, for regulation and frequency response service, the non-generation resource must be able to match and follow the corresponding generation resource provider instantaneously, in the same manner that generation resources now provide this service for load. If the non-generation resource does not have this capability, E.ON U.S. contends that the transmission system could be placed in jeopardy and the transmission provider could be subject to potential reliability penalties.

497. Southern asks the Commission to confirm that demand response resources should satisfy the same reliability criteria for providing ancillary services as are required of generation resources. Specifically, Southern argues that such resources must meet regional reliability council requirements and, if no such requirements have been formalized, balancing authority requirements for the qualification of such resources, so long as those qualification requirements are not unduly discriminatory. Southern contends the Commission's focus in Order No. 890 on the capability of demand resources to provide ancillary services may not take into consideration qualification of those resources under non-discriminatory, reliability-based criteria.

498. Southern also notes that transmission providers have a certain degree of discretion, within the bounds of applicable criteria, to determine the quantity, mix and distribution of resources held to provide various system reliability functions. Southern states, for example, that it holds and maintains reserves from the lowest-cost resources available for that purpose. Southern requests clarification that transmission providers are under no obligation to purchase from non-generation resources on a non-economic basis relative to otherwise comparable generation resources or to somehow discriminate in favor of non-generation based resources.

Commission Determination

499. The Commission affirms the decision in Order No. 890 that the sale of ancillary services by load resources should be permitted where appropriate on a comparable basis to service provided by generation resources. A transmission provider may impose appropriate technical criteria, comparable to the requirements placed on generation resources, in order to reliably allow load resources to provide the different ancillary services. We note that such criteria and requirements have been implemented in RTO markets that allow demand response to participate as an ancillary service resource.[192] As

[192] PJM, for example, allows load resources to provide regulation service, but requires telemetering ability and pre-certification to show the resource can meet the physical characteristics in order for the resource to qualify. To participate in the synchronized reserve market in PJM, demand response resources must install infrastructure such that they can curtail consumption within ten

Southern suggests, any such reliability-based qualification criteria should be developed and imposed on a non-discriminatory basis. We also agree with Southern that transmission providers should give comparable, not preferential, consideration of load resources in selecting the mix of resources to supply ancillary services.

b. Pricing and Procurement of Reactive Power

500. The Commission rejected requests to modify requirements regarding the provision and pricing of reactive power. The Commission reiterated the policy stated in Order No. 2003, *et al.*, that interconnection customers must be treated comparably with the transmission provider and its affiliates in terms of reactive power compensation.[193] If the transmission provider pays its own generators or those of its affiliates for reactive power, then the transmission provider also should pay interconnecting generators for providing reactive power within the specified range.[194] The Commission stated that it would continue to resolve compensation issues for reactive power to qualifying generators on a case-by-case basis.

Requests for Rehearing and Clarification

501. E.ON U.S. requests that the Commission commence a separate rulemaking to address the conflicts that continue to arise regarding reactive power. E.ON U.S. argues that the Commission should provide the proper incentives for locating resources to provide the maximum benefit in terms of reactive power, and that consumers should not be forced to pay for reactive power for units that provide no benefit in terms of reactive capability. E.ON U.S. contends it is inappropriate to compensate units for reactive power unless they are built in a location where reactive power output is desirable from an engineering standpoint and are available in the time period needed in order to be useful to the system. E.ON U.S. contends that initiating a rulemaking to consider the locational requirements for reactive power payments would ensure a good supply of reactive power and reduce the amount of time-consuming and wasteful litigation.

Commission Determination

502. We again decline the request to initiate a separate rulemaking process to address issues regarding compensation for reactive power. The Commission does not believe that acting generically on pricing for reactive power is necessary at this time. As the Commission explained in Order No. 890, we will continue to resolve compensation issues for reactive power to qualifying generators on a case-by-case basis.[195]

c. Operating Reserves

Requests for Rehearing and Clarification

503. Sempra Global contends that the Commission failed to address its comments requesting clarification that transmission providers are obligated to offer and make available operating reserves to a generator located within the transmission provider's control area, even if the generator-customer is serving load outside of the transmission provider's control area. Sempra Global states that various transmission providers within the WECC interpret the requirement to provide operating reserves to customers serving load within the control area differently. Sempra Global explains that some in the WECC have argued that power cannot be sold as firm unless it includes operating reserves and that the current calculation of operating reserve requirements for WECC control area operators includes a netting of firm imports and exports.

504. As a result, Sempra Global argues that transmission providers that operate control areas are able to effectively shift portions of their operating reserve requirements by contracting for firm power from other control areas, provided that the selling control area carries additional operating reserves for the sale. Sempra Global contends that this limits the abilities of generators to make firm power sales to entities outside the control area in which the generator is located. Sempra Global also argues that this practice allows the transmission provider to thwart competition from non-utility generators by limiting the ability of merchant generators to make firm power sales outside of the control area. Sempra Global asks the Commission to clarify that transmission providers are obligated to offer and make available operating reserves regardless of where the merchant generation-customer is serving load.

Commission Determination

505. We disagree with Sempra Global that the transmission provider should be obligated to offer and make available operating reserves under Schedules 5 and 6 of the *pro forma* OATT when transmission service is used to serve load outside the transmission provider's control area. Operating reserves are needed to serve load within the control area in the event of system contingencies. Unless alternative arrangements are made, the transmission provider provides these reserves from its own resources. It would be inappropriate to require the transmission provider to use its resources to provide additional operating reserves to loads in other control areas because the transmission providers in those control areas are under their own obligation to make operating reserves available.

506. We therefore conclude that the existing requirements of the *pro forma* OATT are sufficient to ensure that operating reserves are available to serve the type of transaction discussed by Sempra Global. A generator serving load outside the control area can make alternative comparable arrangements to provide reserves on behalf of its load by contracting with third parties. The generator could also request, as part of its negotiation with a customer, that the customer acquire reserves from its transmission provider as necessary to support the transaction. Modification of the *pro forma* OATT is not necessary to enable generators to engage in firm power sales to loads outside of their control area.

D. Non-Rate Terms and Conditions

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

507. In Order No. 890, the Commission concluded that the methods for evaluating requests for long-term point-to-point transmission service may not be comparable to the manner in which transmission service is planned for bundled retail native load and, therefore, may no longer be just, reasonable and not unduly discriminatory. To remedy this potential for undue discrimination, the Commission amended the *pro forma* OATT to require transmission providers, other than most RTOs and ISOs, to offer a modified form of planning redispatch as well as a conditional firm option to long-term point-to-point customers. A number of

minutes and also must provide metering information needed to account for their response.

[193] *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 68 FR 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g,* Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, 70 FR 37,661 (Jun. 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners* v. *FERC,* No. 04–1148, 2007 U.S. App. LEXIS 626 (D.C. Cir. Jan. 12, 2007).

[194] *Citing* Order No. 2003–B at P 119.

[195] *See* Order No. 890 at P 898.

petitioners have requested rehearing of the Commission's decision to modify the planning redispatch requirements and institute a new obligation to offer the conditional firm option. We first address the threshold requirement to offer these options and then turn to implementation of each option.

a. Requirement To Offer Planning Redispatch and Conditional Firm

508. The requirement to offer planning redispatch was adopted in Order No. 888 under section 19.3 of the *pro forma* OATT. Transmission providers were required to identify, in each system impact study, system constraints as well as redispatch options available to resolve those constraints and provide planning redispatch to the extent redispatch was more economical than the cost of transmission upgrades. In Order No. 890, the Commission modified the planning redispatch requirement, adding specificity to the information required in the system impact study and limiting planning redispatch to an option that is reassessed every two years if the customer chooses not to pay for upgrades. The Commission also removed the limitation of offering planning redispatch only when it is more economical than the cost of transmission upgrades. The Commission rejected arguments against the underlying requirement to offer planning redispatch as collateral attacks on Order No. 888.

509. The Commission also found that transmission providers were using a service analogous to the conditional firm option, in addition to planning redispatch, to serve their own loads. The Commission concluded that transmission providers must evaluate transmission availability to serve long-term firm point-to-point service requests in a manner that is comparable with the method used to evaluate their own transmission needs and to integrate their resources to serve bundled retail native load. The Commission therefore required non-ISO/RTO transmission providers to make available both the planning redispatch and conditional firm options to long-term firm point-to-point customers. The Commission emphasized, however, that transmission providers are not required to offer either the planning redispatch or conditional firm option if doing so would impair the transmission provider's ability to reliably serve other firm customers, including native load and network customers.

510. The Commission also placed several limitations on the nature of the planning redispatch and conditional firm options to limit the their potential impact on reliability. First, the Commission required that the planning redispatch and conditional firm options be made available to long-term point-to-point customers. While a transmission provider might choose to propose planning redispatch or conditional firm on a shorter-term basis, it would not be required to under the *pro forma* OATT. Second, the Commission distinguished between two different types of customers that may request the service: customers who support the construction of upgrades and those who do not. For customers supporting the construction of upgrades, the planning redispatch or conditional firm options need only be offered until the time when the upgrades are constructed. The conditions or redispatch applicable to the interim period must be specified in the service agreement and will not be subject to change. For customers choosing not to support the construction of new facilities, the planning redispatch or conditional firm options must be made available as a reassessment product, *i.e.*, subject to reassessment every two years by the transmission provider. Every two years, or sooner if at the continuation of the term of service, the transmission provider must reassess the redispatch required to keep the service firm or the conditions or hours under which the transmission provider may conditionally curtail the service.[196]

511. With regard to transmission service provided by RTOs and ISOs, the Commission found that it would be inappropriate to require RTOs and ISOs with real-time energy markets to adopt the provisions for conditional firm point-to-point service. The Commission explained that customers transacting in RTOs and ISOs are able to buy through transmission congestion in the real-time energy markets and need no prior reservation in order to access transmission. The Commission did require, however, RTOs and ISOs that already provided planning redispatch pursuant to section 13.5 of the Order No. 888 *pro forma* OATT to modify the relevant provisions of their tariffs consistent with the directives of Order No. 890.[197] RTOs and ISOs not already providing planning redispatch were not required to amend their tariffs to include the planning redispatch option.

512. The Commission declined to adopt the conditional firm option for network service and made no changes to the planning redispatch provisions for network customers.

(1) Planning Redispatch

Requests for Rehearing and Clarification

513. Several petitioners object to the requirement that transmission providers offer planning redispatch point-to-point service.[198] They argue that the planning redispatch requirement can degrade the quality of service to existing firm customers by increasing loop flow and creating reliability problems or by shifting costs to them. They argue that planning redispatch increases curtailment risks to existing customers because generators are used in a manner that is different than the planned use of those generators. Ameren argues that planning redispatch is unduly discriminatory in that it requires the use of the transmission provider's generation resources but not the resources of network customers or third parties. Ameren also argues that planning redispatch is not superior to the options already in place in the *pro forma* OATT adopted in Order No. 888. Other petitioners assert that the modifications to planning redispatch will remove incentives for transmission expansion because planning redispatch will always be cheaper and easier for customers than paying for new transmission capacity.[199]

514. Several petitioners argue that the merits of commenter arguments on planning redispatch should be addressed rather than rejected as collateral attacks against Order No. 888.[200] Ameren asks the Commission to revisit the requirement imposed in Order No. 888 to provide planning redispatch to point-to-point customers as the Commission revisited all Order No. 888 requirements in Order No. 890. E.ON LSE asserts that arguments about the reliability impacts of the planning redispatch service are not barred as collateral attacks because the Commission changed the service by removing the expansion price cap. E.ON LSE states that by removing the expansion cap the Commission placed a burden on transmission providers to provide planning redispatch even if it

[196] The Commission acknowledged that some transmission providers may be able to provide conditional firm service over a period longer than two years without the need for reassessment. In the event a transmission provider is able to extend the assessment period, the Commission stated that waiver or extension of the right to reassess the availability of the option would be permitted, provided that the waiver or extension is provided consistently for all similarly situated service.

[197] The Commission explained such modification would include the transmission provider's obligation to post monthly redispatch costs for each transmission facility over which planning and reliability redispatch are provided.

[198] *E.g.*, Ameren, NRECA, and TDU Systems.

[199] *E.g.*, E.ON LSE, NRECA, and TDU Systems.

[200] *E.g.*, Ameren, E.ON LSE, and Southern.

would be more costly than the construction of transmission upgrades.

515. Ameren and Southern reiterate concerns that modeling of planning redispatch will be challenging given the difficulty of projecting redispatch costs and the availability of generating units, even if the projections are limited to a two-year period. Ameren expects that it may deny service on reliability grounds for every request. Given this expectation, Ameren argues that the Commission should develop clear reliability guidelines so that transmission providers can comply without subjecting themselves to claims of discrimination for denying service. E.ON LSE states that projecting redispatch costs will be difficult and likely result in inaccurate estimates.

516. Other petitioners express concern that a transmission provider may avoid its obligation to provide planning redispatch or conditional firm service by rejecting requests based on an arbitrary, unreasonable and conservative definition of reliability.[201] Constellation states that oversight is necessary to ensure that transmission provider conclusions are sufficient to demonstrate that planning redispatch options were properly considered. EPSA supports publicly posting on OASIS reserve margin measures to eliminate the inflation of margins exceeding reliability requirements. Williams recommends adoption of a reliability standard to ensure the options are not improperly rejected on reliability grounds.

517. Ameren argues that the Commission should grant a blanket exemption from the planning redispatch requirement for all RTOs because: RTO markets are independent; RTOs do not own or operate generation; and the redispatch requirement could exacerbate seams issues and affect the calculation and distribution of financial transmission rights (FTRs). Ameren expresses concern that the planning redispatch requirement will also adversely impact the calculation of the revenue sufficiency guarantee charges in MISO.

518. Several petitioners contend that the obligation to provide the planning redispatch option contradicts section 217 of the FPA to the extent it impinges on native load service.[202] South Carolina E&G argues that requiring transmission providers to offer planning redispatch could marginalize native load, in violation of section 217, unless the Commission modifies section 13.6 of the *pro forma* OATT to eliminate comparable curtailment of native load and non-native load service. South Carolina E&G contends that the Commission is precluded under section 217(k) from making a finding that it is unduly discriminatory if practices governing the evaluation of long-term firm point-to-point service are not comparable to the manner in which transmission service is planned for bundled retail native load. South Carolina E&G contends that recognition of the curtailment primacy of native load service would provide a necessary escape mechanism should the planning redispatch or conditional firm options threaten native load service. South Carolina Regulatory Staff objects to the planning redispatch and conditional firm options to the extent that native load purchasers of electricity are required to bear the costs of additional transmission capacity necessitated by transmission to non-native consumers.

519. E.ON LSE also argues that FPA section 217 prohibits requiring transmission providers to offer native load redispatch to non-native load customers on the basis of claimed discrimination. E.ON LSE asks the Commission to clarify that, in real time, LSEs may use all or a portion of their resources to serve native load rather than redispatch for third parties. E.ON LSE also requests clarification that the generation facilities having restricted run times may be reserved for the use of native load needs and not be offered for firm point-to-point planning redispatch service.

520. NorthWestern requests that the Commission grant waiver of the redispatch requirements for transmission providers who do not have the ability to dispatch generation. Washington IOUs request Commission clarification that when a viable, parallel path is available to a transmission customer to move its power, the transmission provider is not required to offer planning redispatch service. Washington IOUs state that in the Pacific Northwest transmission customers may be able to move power to the same point more easily by purchasing transmission service over a neighboring transmission system. Washington IOUs argue that in such a situation requiring a jurisdictional utility to offer planning redispatch service would unreasonably increase the costs of providing transmission service.

521. Washington IOUs further argue that the Commission erred in not exempting hydro-based systems from the planning redispatch requirements. Washington IOUs argue that the Commission failed to recognize that hydro units may not be available due to recreational, flood control, fish mitigation and other non-power related requirements. Washington IOUs further assert the Commission should exempt hydro-based systems from providing planning redispatch because of possible occurrence of pricing disputes, under-recovery of costs, and disputes over study of planning redispatch opportunities.

522. TAPS asserts that the Commission failed to revise to insert new planning redispatch provisions into *pro forma* OATT section 32.3 pertaining to network service system impact studies. TAPS also argues that the Commission must ensure that transmission service provided to network customers is comparable to the service transmission providers provide themselves through planning redispatch and low granularity system models. TAPS argues that transmission providers use planning redispatch combined with their system-wide modeling to designate network resources that otherwise might be undeliverable. TAPS asserts they do this by treating their control areas as a whole for sink purposes while selectively disaggregating their resources for sourcing purposes. TAPS asserts that undue discrimination arises because a network customer's request to bring on new network resources is modeled with granularity, without the benefit of planning redispatch and the redispatch assumed by modeling the transmission provider's own load as a single system sink when designating resources. TAPS asks the Commission to redress this discrimination by prohibiting the transmission provider from denying any request for transmission to a network customer, or requiring upgrades or mitigation, the costs of which are not shared on a load-ratio basis, if the request would have been accepted if the transmission provider's own load had been the designated sink.

523. Finally, EEI requests clarification of the length of the service request that would qualify for these options. EEI notes that sections 15.4(b) of the *pro forma* OATT does not qualify the provision of planning redispatch only to long-term firm point-to-point customers. EEI asks the Commission to amend sections 15.4(b) of the *pro forma* OATT to make this section consistent with the statements in Order No. 890 providing that a transmission provider is obligated to provide planning redispatch service to customers requesting long-term firm point-to-point service, but not to customers requesting short-term firm service.

[201] *E.g.*, Constellation, EPSA, and Williams.

[202] *E.g.*, E.ON LSE, South Carolina E&G, South Carolina Regulatory Staff, and Southern.

Commission Determination

524. The Commission affirms the decision in Order No. 890, originally established in Order No. 888, to require transmission providers to redispatch their generation resources in certain circumstances to create additional capacity on the transmission grid. Petitioners arguing for removal of this requirement have failed to show any actual degradation of reliability, degradation of service to other firm customers, or delay in grid expansion caused by planning redispatch service during the first 10 years in which the requirement was in place. We therefore decline to eliminate this long-standing option for point-to-point customers.[203]

525. We also affirm the limitation placed on the planning redispatch requirement, which we believe adequately address petitioners' concerns regarding potential effects on reliability or service quality. The Commission in Order No. 890 scaled back the obligation to provide planning redispatch service by severing the link between it and transmission upgrades, no longer requiring the provision of planning redispatch for an indefinite period.[204] Under the modified planning redispatch option, transmission customers must agree to pay for transmission upgrades or agree to have the conditions of their planning redispatch service reassessed every two years. These modifications more appropriately balance customers' needs with transmission providers' reliability and native load obligations. Planning redispatch service under Order No. 890 is, therefore, superior to that service under Order No. 888, contrary to Ameren's assertions.

526. We disagree that planning redispatch will remove incentives for transmission expansion. As modified in Order No. 890, planning redispatch may provide a means for greater transmission investment as customers will be able to receive the bridge service prior to the completion of upgrades. The benefit of immediate access to the transmission grid could result in more attractive financing and cash flow options for new resources, in turn resulting in more investment in transmission. Moreover, customers taking the reassessment product may identify over time others willing to jointly fund upgrades, leading to further investment. In asserting a negative impact on transmission expansion, petitioners imply that planning redispatch will always be a less expensive option than investment in upgrades. But if that were true then planning redispatch would have proliferated over the last 10 years given that transmission providers were obligated to provide planning redispatch if it was more economical than transmission upgrades.

527. Petitioners' concerns about harms to existing customers through increases in loop flow and curtailment risks are not unique to rights granted through the use of planning redispatch. The efficient use of the existing transmission grid, including every incremental new firm use, brings with it an increased risk in the instances and megawatt quantity of curtailment for all existing users of the grid. As the Commission explained in Order No. 890, the modifications to planning redispatch will enable transmission providers to better manage the risks of curtailment for current users of the transmission grid because the obligation to redispatch will no longer be open-ended.[205] We reject TDU Systems' assertion that planning redispatch will increase costs for network customers because it is based upon an incorrect assumption that Order No. 890 would require transmission providers to redispatch network customers' resources for point-to-point customers.[206]

528. We disagree with NRECA and TDU Systems that planning redispatch service increases curtailment risk because generation is used differently than planned. By definition, transmission providers must study the resources that they will redispatch in order to offer each individual planning redispatch service. Thus, generation will be used by transmission providers as planned. While we acknowledge that planning redispatch service presents complicated modeling issues, even when limited to a two-year period, modeling difficulties exist throughout the utility industry. If anything, the modifications to the planning redispatch option adopted in Order No. 890 lessen the modeling burden by scaling back the planning redispatch requirement.

529. With regard to loop flows, we agree with NRECA that changing and unpredictable loop flows make it more difficult for system operators to understand their systems and respond to contingencies properly. We do not agree, however, that planning redispatch will have any greater adverse effect on loop flows than the addition of a new generator to the grid or the addition of or a change to a firm point-to-point use. The effects of planning redispatch service will be studied in a system impact study well before the service is provided, like any other proposed firm use of the system. Transmission providers will therefore be able to adjust to planning redispatch uses of the system in the same way they now adjust to additions of generation and all new or changed firm point-to-point uses.

530. Planning redispatch service does not unduly discriminate against transmission providers by requiring them to use their resources to provide service. The Commission does not require the use of network customer and third party resources to provide planning redispatch point-to-point service because third parties and network customers do not provide the associated transmission service. Third parties or network customers that create additional grid capacity by redispatching, such as through a transaction that flows counter to the majority of flows on a line, cannot sell the additional transmission capacity that they create. A transmission provider using its resources to serve loads on its system can however create and sell additional transmission capacity on its system through control of those resources. It is therefore not unduly discriminatory to require the use of transmission provider resources to provide planning redispatch to long-term point-to-point customers.

531. We decline to develop reliability guidelines or standards for implementing planning redispatch. The underlying obligation to provide planning redispatch has been in place for 10 years without such guidelines. This is not surprising given that each transmission system is different and any industry-wide guidelines would necessarily be over- or under-inclusive. Transmission providers must already comply with those reliability standards approved by the Commission and we will not unnecessarily layer additional standards upon the transmission providers for planning redispatch or conditional firm service. Transmission providers should retain responsibility for incorporating reasonable

[203] Arguments that the Commission has no authority to impose a planning redispatch obligation are a collateral attack on Order No. 888. We disagree with E.ON LSE's assertion that removal of the expansion cap placed a new burden on transmission providers by fundamentally changing the nature of the service. While Order No. 890 required planning redispatch to be provided even when it is more expensive than transmission upgrades, service is only guaranteed for two years if customers do not pay for upgrades. This puts a bound upon the service for transmission providers that benefits rather than burdens them.

[204] Order No. 890 at P 926.

[205] *See id.* at P 593.

[206] TDU Systems cites to an argument made by NRECA that concerns the transparent dispatch advocates' proposal for inclusive bid-based real-time redispatch. NRECA Supplemental, Affidavit at 27.

assumptions into their models in order to manage risks.

532. We do, however, clarify herein additional valid reasons for denying service on reliability grounds. We will not require publication of the metrics underlying these reliability grounds or, as EPSA requests, identification of reserves set aside for customers; these metrics likely contain competitive information or relate to state-imposed requirements. If eligible customers believe they have been unreasonably denied redispatch or conditional firm service on reliability grounds, they should bring the matter to the Commission's attention through a complaint or other appropriate procedural mechanism. Transmission providers can proactively address claims of discrimination resulting from denials of planning redispatch (or conditional firm) service by publishing modeling assumptions and free flow of information between the transmission provider and potential customers.[207]

533. Concerns about a transmission provider's inability to project redispatch costs are misplaced. In Order No. 890, the Commission directed transmission providers to provide eligible customers with non-binding estimates of the incremental costs of redispatch.[208] The Commission expects that transmission providers will use due diligence in providing the costs estimates, but as with any non-binding estimate they will not be liable for their inability to accurately predict future costs.

534. The Commission grants rehearing of the decision to require RTOs and ISOs to modify planning redispatch provisions that remain in their tariffs. The tariffs of many RTOs and ISOs were developed to layer energy markets and financial transmission rights on top of the existing *pro forma* OATT physical rights systems. Upon consideration of petitioner's arguments, we conclude it is more appropriate not to disturb these developments by requiring changes to the existing planning redispatch provisions stated in sections 13.5, 15.4, 19.1 and 19.3 of the *pro forma* OATT.[209]

535. We will not, however, grant RTOs and ISOs a blanket exemption from the planning redispatch requirement, as requested by Ameren. RTOs and ISOs that currently offer planning redispatch in addition to the redispatch offered through their energy markets prior to issuance of Order No. 890 must continue to provide that service.[210] Where such service is offered, customers should not be excluded from accessing the service through planning redispatch unless the Commission has previously found or finds in the future that such exclusion is consistent with or superior to the provisions of the *pro forma* OATT. The exacerbation of seams issues and disruption of FTR processes are issues that we would consider if an RTO or ISO seeks to terminate its existing planning redispatch service.[211]

536. We also decline to provide a blanket exemption from the planning redispatch requirement for transmission providers without generation or the ability to dispatch generation. We clarify, however, that transmission providers without the ability to dispatch generation cannot reliably provide planning redispatch service and have no obligation to procure generation to provide the service. We deny a blanket exemption because transmission providers' situations can change over time so that they gain the ability to dispatch generation.

537. We affirm our decision to not generically exempt hydroelectric-based systems from the provision of planning redispatch service. Contrary to Washington IOU's assertion, the Commission took into consideration the fact that hydroelectric units may not be available due to recreation, flood control or fish mitigation when it acknowledged the ''added difficulty of predicting water availability'' in hydroelectric systems.[212] While there is potential for disputes regarding the availability and cost of a hydroelectric unit, such disputes are not unusual for other types of units that are equally subject to the planning redispatch requirements.

538. We disagree that the availability of firm transmission service over a parallel path on another transmission provider's system should relieve a transmission provider of the obligation to provide planning redispatch. In order to obtain planning redispatch service, a customer must agree to and pay for a system impact study, await the results of the study and sign a non-conforming transmission service agreement. We would not expect a customer to undertake the more complicated process of obtaining planning redispatch if the transmission service meeting the customer's needs is available elsewhere. We therefore see no need to limit the availability of planning redispatch service as Washington IOUs request.

539. It is not necessary to amend the curtailment priorities under the *pro forma* OATT in order for the planning redispatch requirement to be consistent with FPA section 217, as South Carolina E&G contends. As we explain in section II.B, section 217(b) provides certain protections to a specified class of utilities using their firm transmission rights, to the extent required to meet their service obligations. The provision of planning redispatch does not impair the use of those firm transmission rights, or otherwise marginalize native load, notwithstanding the curtailment priorities established in section 13.6 of the *pro forma* OATT. As the Commission explained in Order No. 890, there is no obligation to offer planning redispatch if it either (i) degrades or impairs the reliability of service to native load customers, network customers and other transmission customers taking firm point-to-point service or (ii) interferes with the transmission provider's ability to meet prior firm contractual commitments to others. We clarify that this exempts transmission providers from providing planning redispatch from resources that are expected to provide reliability redispatch in response to constraints. Further, if resources with restricted run times are required to meet the reliable service needs of native load, including reliability redispatch needs, these resources need not be offered for planning redispatch service. The obligation to offer planning redispatch is therefore consistent with the requirements of section 217.

540. Contrary to South Carolina Regulatory Staff's assertions, native load will not bear the costs of additional transmission capacity created through either the planning redispatch or conditional firm options. While the

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[207] We note that increased information regarding the modeling, data, and assumptions used by the transmission provider to calculate ATC and plan the system must now be made available under Attachments C and K to the *pro forma* OATT.

[208] Order No. 890 at P 958.

[209] To the extent an RTO or ISO has already incorporated this new language into its OATT in a prior compliance filing, removal of that language is at the RTO's or ISO's discretion.

[210] For example, although SPP does not own generation, transmission owners within SPP retain the obligation through SPP's Attachment K to use their resources to provide planning redispatch for firm transmission service. *See* Southwest Power Pool FERC Electric Tariff Fifth Revised Volume No. 1, Attachment K, section B, Original Sheet No. 238–239 (Effective February 1, 2007).

[211] Ameren's concern with disruption of MISO's revenue sufficiency guarantee and FTR allocation processes due to implementation of the planning redispatch requirement is misplaced. Under MISO's tariff, the provisions of Module C (Energy Markets, Scheduling and Congestion Management) or the ITC Rate Schedule apply if redispatch is more economical than constructing transmission upgrades. *See* Midwest ISO Transmission and Energy Markets Tariff, section 13.5. MISO need not change its tariff provisions for the management of redispatch through its energy markets because the Commission has already accepted them as consistent with or superior to the Order No. 888 *pro forma* OATT.

[212] Order No. 890 at P 948.

options could lead to the construction of more transmission if customers agree to pay for transmission upgrades, during the period these services are provided they do not require the construction of transmission upgrades. Rather, they are provided by curtailing the customer or redispatching the transmission provider's resources to create long-term firm transmission. Moreover, costs otherwise recovered from native load customers are reduced by the additional revenues gained by the additional sales of conditional firm and planning redispatch service.

541. We also disagree that FPA section 217(k) precludes the Commission from finding that it is unduly discriminatory for transmission providers to engage in planning redispatch to serve native load while refusing to provide comparable service to long-term point-to-point customers. The intent of section 217(k) is to preserve the use of certain firm transmission rights to the extent required to meet the service obligations of a class of specified utilities. The statute thus protects these utilities' continued use of protected firm transmission rights during periods of constraint or emergency, when service might not otherwise be available. The transmission provider's use of planning redispatch (as well as conditional firm service) occurs *prior* to the occurrence of such conditions, when the transmission provider decides to bring a new resource onto its system. It is therefore unduly discriminatory for the transmission provider to refuse to make planning redispatch (or conditional firm service) available to similarly situated customers. Indeed, this furthers the intent of FPA section 217 by facilitating the ability of all long-term users of the transmission system to meet their service obligations, which the statute defines broadly to include not only service to end-users, but also to distribution utilities serving end-users.[213]

542. We agree with TAPS that Order No. 890 inadvertently failed to make modifications to section 32.3 that correspond to the amendments to 19.3 of the *pro forma* OATT to provide more information for customers requesting the planning redispatch option. We revise section 32.3 to make clear that the information required in a system impact study is nearly identical for network and point-to-point customers. We note that the amended section 32.3 only requires a transmission provider to provide an estimate of costs for the network customer to the extent it has cost data for the relevant network customer's resources.

543. However, we deny TAPS' request to address here the granularity of system modeling necessary to implement planning redispatch service. The ATC and planning-related reforms adopted in Order No. 890 will help address TAPS' granularity issue once these reforms are implemented. Transmission providers have been directed to address the effect on ATC of designating and undesignating network resources as part of the ongoing NERC/NAESB standardization effort.[214] To the extent TAPS has concerns regarding the modeling of ATC to respond to requests to designate network resources, those concerns should be addressed in the first instance through the NERC/NAESB process. We make no further changes to the planning and reliability redispatch services in the existing *pro forma* OATT as these services are already provided comparably to network customers.

544. We agree with EEI's requested change to provide consistency between the *pro forma* OATT and the preamble of Order No. 890. As the Commission stated repeatedly in Order No. 890, transmission providers are obligated to provide planning redispatch options only to customers requesting long-term firm point-to-point service.[215] We amend section 15.4(b) of the *pro forma* OATT accordingly. We also revise sections 19.1 and 19.3 of the *pro forma* OATT to make clear that the planning redispatch option is available to eligible customers, not just existing transmission customers, as provided in Order No. 890.

(2) Conditional Firm

Requests for Rehearing and Clarification

545. Several petitioners object to the Commission's decision to require transmission providers to offer conditional firm point-to-point service.[216] Ameren states that the conditional firm option is not superior to the options already available to customers under the *pro forma* OATT adopted in Order No. 888. Ameren contends that the conditional firm service options create more discretion and uncertainty in the processing of service requests, contrary to the Commission's stated goal of increasing transparency in the provision of transmission service. Ameren expresses concern that ill-defined conditional firm service rules could lead to non-compliance and assessment of significant penalties. Ameren and NorthWestern argue that, at a minimum, the Commission must provide detailed guidelines and limit the discretion of transmission providers in studying conditional firm service options. Ameren states that allowing conditional firm transmission to be curtailed only during selected events offers less system reliability. Ameren and NRECA ask the Commission to limit or remove the obligation to provide conditional firm service because maintaining the service will degrade reliability as system planners and operators must account for more and varied uses of the system and manage increased loadings on the system. If it is not allowed to deny service for the degradation of reliability that would occur with every service request involving conditional firm, Ameren asks that the Commission develop clear reliability guidelines so that transmission providers can comply without subjecting themselves to claims of discrimination for denying service.

546. South Carolina E&G and South Carolina Regulatory Staff contend that the obligation to offer the conditional firm option contradicts section 217 of the FPA to the extent it impinges on native load service. South Carolina E&G states that granting a secondary network service curtailment priority during conditional curtailment periods could adversely affect the reliability of native load service in direct violation of section 217 of the FPA. South Carolina E&G states that native load customers use secondary network service for redispatch when the system becomes constrained; therefore, allowing increased use of this priority non-firm service by conditional firm service customers will adversely affect native load customers in violation of FPA section 217. South Carolina E&G also argues that FPA section 217(k) precludes the Commission from finding that the practice of using conditional firm by transmission providers is unduly discriminatory.

547. MidAmerican requests clarification that transmission providers are not prohibited from voluntarily offering the conditional firm option for short-term point-to-point service. MidAmerican also requests Commission clarification that Order No. 890 did not require transmission providers to submit revised tariff sheets if the transmission providers already provide short-term conditional firm service.

548. Some petitioners ask the Commission to create a conditional firm network service.[217] TAPS and NRECA

[213] *See* EPAct 2005 sec. 1233(a)(3) (to be codified at section section 217(a)(3) of the FPA, 16 U.S.C. 824q(a)(3)).

[214] *See* Order No. 693 at P 1041.

[215] *See, e.g.*, Order No. 890 at P 4, 78, and 911.

[216] *E.g.*, Ameren, NRECA, and TDU Systems.

[217] *E.g.*, NRECA, TAPS, and TDU Systems.

contend that limiting the conditional firm option to long-term firm point-to-point service is inappropriate in light of the Commission's finding that transmission providers provide themselves conditional firm network service. TAPS and NRECA argue that the Commission has allowed continued discrimination as between transmission providers and network customers. TAPS argues that Order No. 890 enables transmission providers to continue to designate resources on a conditionally firm basis, but denies network customers the same right to do so.

549. NRECA and TDU Systems also contend that conditional firm network service is required to preserve network customers' ability to access those resources that they are able to obtain today through redirect service without being bumped by conditional firm point-to-point customers. In their view, conditional firm network service would prevent gaming and hoarding by point-to-point customers through use of conditional firm service and achieve parity in flexibility through use of secondary network service. TDU Systems assert that the provision of conditional firm network service is essential to ensure that network customers can receive the same priority in maintaining transmission access rights as those granted to conditional firm point-to-point customers.

550. NRECA and TDU Systems argue that allowing conditional firm for the import of designated network resources but not allowing it for in-control area transactions is irrational, creates perverse operational incentives and does not make legal sense. By way of example, NRECA states that a resource could be designated to serve load in a neighboring control area, but not in the control area in which the resource is located. NRECA contends that creation of a conditional firm network service would provide additional support to intermittent resources that wish to sell their services in the control area in which these resources are located.

551. Finally, EEI requests clarification of the length of the service request that would qualify for these options. EEI notes that sections 15.4(c) of the *pro forma* OATT does not qualify the provision of conditional firm service only to long-term firm point-to-point customers. EEI asks the Commission to amend sections 15.4(c) of the *pro forma* OATT to make this section consistent with the statements in Order No. 890 providing that a transmission provider is obligated to provide conditional firm service to customers requesting long-term firm point-to-point service, but not to customers requesting short-term firm service.

Commission Determination

552. The Commission affirms the decision in Order No. 890 to create a new conditional firm option in the *pro forma* OATT for customers seeking and denied long-term firm point-to-point transmission service.[218] We reiterate that, like the planning redispatch option, transmission providers are not required to provide conditional firm service if doing so would impair system reliability. Concerns regarding system reliability have thus already been addressed in the design of the conditional firm option.

553. We disagree with Ameren that the conditional firm option will create more discretion and uncertainty in processing of service requests. In Order No. 890, the Commission provided a detailed description of the characteristics, requirements and implementation of the new option, developed through multiple industry sessions and with supplemental comments. Ameren argues that the obligation to offer the conditional firm option should be eliminated unless the Commission provides further guidance regarding how to study its availability, yet Ameren does not identify the particular details that it believes are missing. Even if there is some initial uncertainty in the processing of service requests as transmission providers become comfortable with studying the conditional firm option, it is more than offset by the reduction in uncertainty faced by eligible customers whose service requests would otherwise have been rejected for lacking as little as one hour of firm service during the year.

554. We decline to develop reliability guidelines for the provision of conditional firm service, as Ameren requests. Each transmission system will have a different ability to accommodate varying requests for conditional firm service. As with planning redispatch, any guidelines we create would necessarily be over or under-inclusive and either jeopardize the reliability of some transmission providers' systems or unnecessarily restrict the amount of conditional firm service that may be offered. Transmission providers may determine the amount of conditional firm service that they can reliably provide, as long as they do not reject requests from similarly situated customers.

555. We disagree that requiring transmission providers to offer conditional firm service violates FPA section 217. As we explain above, section 217 provides certain protections to a specified class of utilities using their *firm* transmission rights, to the extent required to meet their service obligations. By its very nature, conditional firm service will be conditional when the transmission provider cannot accommodate additional firm service in light of other commitments, including the firm service obligations of LSEs on its system or other existing customers. Moreover, transmission providers are not required to offer the service if doing so would impair system reliability. The restrictions placed on conditional firm service are thus consistent with, and not in contrary to, the requirements of FPA section 217.

556. We also disagree with South Carolina E&G that conditional firm service violates FPA section 217 because it will increase the amount and use of secondary network service, in competition with the use of secondary network service by native load. Secondary network service, also called priority non-firm service, is a non-firm transmission right. Increased use of secondary network service by conditional firm customers therefore does not disturb the use of firm rights protected by section 217. Similarly, FPA section 217(k) does not preclude our finding that failure to offer the conditional firm option is unduly discriminatory since the conditional nature of the service is not within the scope of service protected by FPA section 217(b).

557. We clarify in response to MidAmerican that a transmission provider that provided short-term conditional firm service prior to issuance of Order No. 890 need not revise the existing tariff provisions relating to short-term firm service.[219] A transmission provider proposing to add short-term conditional firm service to its OATT must seek approval under FPA section 205. In either case, the voluntary provision of short-term conditional firm service does not relieve the transmission provider from the obligation to provide long-term conditional firm point-to-point service.

558. We affirm the decision in Order No. 890 not to create a conditional firm network service. Network customers may designate network resources any time firm transmission is available, and

[218] As stated above, RTOs and ISOs with real-time energy markets are not required to offer the conditional firm option. Also, those transmission providers that do not provide long-term firm point-to-point service are exempt from providing conditional firm point-to-point service.

[219] *See* Order No. 890 at P 135, n.106.

the term of the designation can include periods of less than a year. Network customers can also use secondary network service to access resources during times when firm service is not available. This flexibility to use designated network resources and secondary network service to access undesignated resources already provides a service that is like conditional firm service that can be used to integrate new resources, intermittent or otherwise.

559. We agree, however, that transmission providers must study the use of automatic devices when requested by a network customer in a system impact study. In Order No. 890, the Commission found that transmission providers employ automatic devices, such as special protection schemes, to take resources offline during certain system conditions. Comparability requires the study of these automatic devices for network customers seeking to designate network resources. We disagree with TAPS that comparability further requires the same service as between network customers and point-to-point customers. In Order No. 890, the Commission reiterated that network service and point-to-point service were not designed to be identical and, therefore, the rights and obligations of each type of customer need not be the same.[220] We therefore deny rehearing requests to create a network service that is the same as conditional firm point-to-point service, but revise section 32.3 of the *pro forma* OATT to require the study of automatic devices at the request of a network transmission customer.

560. We acknowledge that conditional firm point-to-point service may have an impact on a network customer's use of secondary network service due to increased use of priority non-firm service, but note that the conditional firm option does not reduce the availability of secondary network service any more than the use of short-term firm point-to-point service. Conditional firm point-to-point service could not possibly disrupt a network customers use of redirect service because network customers may not redirect their service,[221] as NRECA argues, nor does the conditional firm option disrupt the network customer's use of point-to-point service to secure off-system resources, since network customers may take conditional firm point-to-point service if they choose. Finally, NRECA's concerns regarding potential hoarding are based on a mistaken belief that customers taking conditional firm service are not charged the long-term transmission rate. The Commission made clear in Order No. 890 that customers taking the conditional firm option pay the rate for long-term firm point-to-point service.[222]

561. We agree with EEI's requested change to provide consistency between the *pro forma* OATT and the preamble of Order No. 890. As the Commission stated repeatedly in Order No. 890, transmission providers are obligated to provide conditional firm options only to customers requesting long-term firm point-to-point service.[223] We amend section 15.4(c) of the *pro forma* OATT accordingly. We also revise sections 19.1 and 19.3 of the *pro forma* OATT to make clear that the conditional firm option is available to eligible customers, not just existing transmission customers, as provided in Order No. 890.

b. Implementation of Planning Redispatch and Conditional Firm

(1) Characteristics of Service

562. The Commission explained in Order No. 890 that the planning redispatch and conditional firm options were not services distinct from point-to-point transmission service, but rather a modification to the procedures for granting long-term point-to-point service and the curtailment priorities for that service. The primary purpose of each option is to address the ''all or nothing'' problem associated with the current procedures for requesting long-term point-to-point service. Where a request for long-term point-to-point firm transmission service is made and cannot be satisfied out of existing capacity, the transmission provider must, at the request of the customer and in the system impact study, identify (i) the transmission upgrades necessary to provide the service and (ii) the options for providing service during the period prior to completion of those transmission upgrades. If upgrades cannot be completed prior to expiration of the requested service term, the transmission provider must, at the request of the customer and in the system impact study, identify options for providing the service during the requested term. The options studied by the transmission provider must include both planning redispatch and conditional firm options. The transmission provider, at its discretion, may study and offer a mix of planning redispatch and conditional firm options for a single service request.

563. If the transmission provider determines that planning redispatch or conditional firm options are available, the system impact study must identify the following: (i) The system constraints, identified by transmission facility or flowgate, causing the need for the system impact study; (ii) additional direct assignment facilities or network upgrades required to provide the requested service; (iii) redispatch options, including the relevant congested transmission facilities for which redispatch will be provided, the generation resources that can relieve those congested facilities, the impact of each identified resource on the congested facilities, and an estimate of the incremental costs of redispatch; and (iv) conditional firm options, including the annual number of conditional curtailment hours and the specific system conditions during which conditional curtailment may occur.[224] Transmission providers may recover the costs of studying these options through the system impact study agreement.

564. If the customer agrees to take service, the service agreement must specify the relevant congested transmission facilities and whether the transmission provider will provide planning redispatch, a mix of planning redispatch and conditional firm, or conditional firm in order to provide the point-to-point transmission service. For the conditional firm option, customers must choose among, and the service agreement must specify, either (i) specific system condition(s) during which conditional curtailment may occur[225] or (ii) annual number of conditional curtailment hours during which conditional curtailment may occur.[226] In situations in which the customer commits to paying the costs

[220] *See id.* at P 1093.

[221] *See id.* at P 1612.

[222] *See id.* at P 1047.

[223] *See, e.g., id.* at P 4, 78, and 911.

[224] The Commission did not require a standardized method of modeling the hours in which conditional firm point-to-point service would be conditional, although it did state addition of a risk factor to their calculation of annual curtailment hours would be appropriate to account for forecasting risks.

[225] Acceptable system conditions could include designation of limiting transmission elements, such as a transmission line, substation or flowgate. The Commission stated its belief that designation of system load levels, standing alone, would not qualify as an acceptable system condition. Load levels would have to be linked to a specific constraint or transmission element that is associated with the request for service, *e.g.*, load levels in a constrained load pocket.

[226] Although the Commission did not require use of monthly or seasonal caps, it encouraged transmission providers to offer them if they can overcome modeling barriers, since monthly or seasonal caps would give more certainty to customers regarding the particular aspects of their service.

associated with upgrades necessary to provide the service on a fully firm basis, the conditions or hours identified by the transmission provider must remain in effect until such time as the upgrades have been completed. For such customers, the service agreement must specify the upgrade costs as determined through the facilities study.

565. Any service agreement that incorporates planning redispatch or conditional firm options will be considered a non-conforming agreement and must be filed by the transmission provider pursuant to FPA section 205. Transmission providers therefore must also file with the Commission any amendments to these service agreements that result from reassessments. If a transmission provider proposes to change the redispatch or conditional curtailment conditions due to a reassessment, the Commission obligated transmission providers to provide the reassessment study to the customer along with a narrative statement describing the study and reasons for changes to the curtailment conditions or redispatch requirements no later than 90 days prior to the date for imposition of these new conditions or requirements.

566. During non-conditional periods, conditional firm service is subject to pro rata curtailment consistent with curtailment of any other long-term firm service. During the hours or specific system conditions when conditional firm service is conditional, conditional firm service share the same curtailment priority as secondary network service. In such circumstances, transmission providers will be allowed to curtail only for reliability reasons and conditional firm customers during conditional curtailment hours will be curtailed only after all point-to-point non-firm customers have been curtailed. If the customer selects the annual hourly cap option, the transmission provider will have the flexibility to conditionally curtail the customer for any reliability reason during those hours, including but not limited to, the system condition(s) identified in the system impact study.

567. The Commission provided that short-term firm service reserved prior to the reservation of conditional firm service will maintain priority over conditional firm service in the periods when conditional firm service is conditional, *i.e.*, when specified system conditions exist or conditional curtailment hours apply. Transmission providers were directed to work with NAESB to develop the appropriate communications protocol to allow for automatic assignment of short-term firm point-to-point service to conditional firm customers to the extent short-term service becomes available. Transmission providers need not implement this requirement until NAESB develops appropriate communications protocols.

568. Transmission providers also were directed to work with customers to facilitate the use of third party generation, where available, in provision of planning redispatch. To facilitate provision of redispatch service by third parties, the Commission further directed transmission providers, working through NAESB, to modify their OASIS sites and develop any necessary business practices to allow for posting of third party offers to provide planning redispatch. Again, transmission providers were not required to implement the new OASIS functionality and any related business practices until NAESB develops appropriate standards.

569. Finally, the Commission recognized that there may be some regional variation in the way transmission providers approach the provision of conditional firm service beyond the minimum attributes that established in Order No. 890. The Commission directed transmission providers located in the same region to coordinate among themselves to develop business practices for implementation of the conditional firm service.[227] In order to allow time for this regional coordination, the Commission directed transmission providers to implement these mechanisms and business practices within 180 days after the publication of this Final Rule in the **Federal Register**, or October 11, 2007.

Requests for Rehearing and Clarification

570. AWEA argues that the Commission erred in limiting the term of planning redispatch and conditional firm services. AWEA contends that longer-term planning redispatch and conditional firm services would better meet the needs of customers seeking long-term service that are unable to secure transmission upgrades because they are uneconomic. If the Commission declines to eliminate temporal limitations on the transmission provider's obligation to offer these services, AWEA asks the Commission to extend the reassessment period from two years to five years. AWEA argues that a five year reassessment period may allow customers to secure financing and would be reflective of a more typical planning horizon.

571. In contrast, NRECA asks that the Commission not allow planning redispatch or conditional firm point-to-point service unless customers agree to pay for transmission upgrades. NRECA argues doing so will eliminate the transmission customer's incentive to free-ride on transmission capacity built and paid for by others. Southern requests clarification that transmission customers committing to transmission construction have a higher priority for the incremental transmission capacity created by their upgrades than planning redispatch or conditional firm customers. If this priority is not granted, Southern maintains that planning redispatch and conditional customers not willing to commit to such construction could firm up their product by waiting for later-queued customers to pay for and construct the upgrades.

572. EEI and Southern argue that bridge customers should also be subject to the biennial reassessment when the period for completing upgrades exceeds two years. EEI contends that, unlike reassessment customers, bridge customers receive a lower quality of service compared to non-bridge customers because the transmission provider makes their determinations using the lowest ATC conditions that occur during the entire term of the bridge service agreement. EEI argues that the transmission provider therefore incorporates a larger margin of risk into its initial offer of service to the bridge customer than would be necessary if it were able to reassess the service biennially.

573. Constellation and EPSA request clarification that the biennial reassessment is not a *de novo* review of whether or not to provide conditional firm service and, instead, is limited to evaluation of the triggering conditions that were identified in the initial analysis. EPSA argues that if the transmission provider's studies show that only one of 10 key facilities raises reliability concerns that warrant an offer of conditional firm service, the transmission provider must be required to plan for and maintain all facilities other than the one identified limiting element on an ongoing basis. Otherwise, EPSA contends, conditional firm service denigrates into a two year service obligation. MidAmerican asks the Commission to confirm that transmission providers can waive their rights to reassess planning redispatch and conditional firm service for all similarly situated customers. MidAmerican suggests that transmission

[227] The Commission encouraged participation of non-public utility transmission providers in the region and interested transmission customers in the development of these business practices, and directed public utility transmission providers to make efforts to include these interested parties in their regional coordination efforts.

providers be able to waive reassessment rights for customers in areas experiencing infrequent changes, but maintain their reassessment rights for other customers in areas that experience frequent changes. MidAmerican contends that a transmission provider's act of waiving the reassessment should not be considered an act of discretion that requires an OASIS posting. MidAmerican also requests clarification that waiver of one reassessment period does not constitute an infinite waiver of reassessment rights. EEI asks the Commission to confirm that the transmission customer bears responsibility for the costs of the biennial reassessments since they are performed in response to its service request.

574. E.ON U.S. expresses concern that, if transmission providers are completely divorced from the third-party provided planning redispatch, there may be a negative impact on system reliability and ATC. E.ON U.S. requests clarification that the reliability coordinator for the transmission system must oversee third-party provision of planning redispatch to avoid interference with reliability redispatch.

575. MidAmerican seeks rehearing of the Commission's decision to expand the scope of the conditional firm option beyond the original NOPR proposal to include curtailment based on system conditions. MidAmerican asserts that this expansion assumes that the system has a built-in ability to absorb scheduled flow of energy from full utilization of firm or network service plus flows from contingent firm service upon an instantaneous system contingency until an operator can curtail conditional firm service. MidAmerican argues that contingencies on certain systems, such as systems susceptible to rapid voltage collapse and cascading outages, can occur before the operator can respond by curtailing.

576. Some petitioners argue that the transmission provider, not the transmission customer, should choose whether conditional firm curtailment will be based on an identified system condition or number of annual hours.[228] Ameren asserts that a system contingency event is not interchangeable with a number of hours limitation because they produce vastly different impacts on the system. Ameren and E.ON U.S. contend that modeling processes and changes in system conditions provide uncertainty and will hinder the transmission provider from specifying accurate curtailable hours. NRECA suggests that the decision of which approach to use should be driven by the results of the transmission provider's studies, local system conditions governing the availability of transmission, and a concern for preserving the reliability and value of existing firm service. E.ON U.S. asks the Commission to acknowledge that the risk factor associated with the number of hours that a customer can be curtailed for conditional firm service may be substantial to reflect the possibility of unexpected events such as a car accident, hurricane, or ice storm that require curtailment of transmission over a certain path.

577. EEI argues that the Commission should grant rehearing regarding the curtailment priority of conditional firm service during conditional periods. To allow the same curtailment priority as secondary network service, EEI asserts, would adversely impact reliable service to network and native load customers because these customers use ''secondary network service in order to serve network loads reliably.'' [229] Additionally, EEI argues that providing a curtailment priority that is below that of secondary network service instead of equal to it does not violate the prohibition against undue discrimination or impact comparability.

578. Southern, EEI and Transerv state that there is no automated process in NERC's Interchange Distribution Calculator (IDC) to convert a tag from firm priority to non-firm priority in order to accommodate conditional firm service. EEI states that currently the only way to modify the curtailment priority reflected on a tag is to cancel the existing tag and issue a new one. According to EEI, this affects the quality of service and ultimately causes the customer to incur imbalance charges. Southern, EEI and Transerv encourage implementation of uniform tagging business practices developed by NAESB to bring greater uniformity to markets. Transerv and EEI also request that the implementation deadline be extended to allow time for these modifications.

579. Southern also argues that the conditional firm service requirements may conflict with NERC reliability standards which require the transmission provider to demonstrate that its transmission system is planned such that it can be operated to supply projected demands and firm transmission services. Southern contends that if conditional firm service is modeled in the base case, it will cause overloads under N–1 contingencies resulting in the curtailment of firm transactions in contravention of NERC planning criteria. Southern asks the Commission to clarify that a transmission provider will not be in violation of NERC reliability standards by providing conditional firm service or if so that civil penalties will not be imposed for such violations.

580. TDU Systems ask the Commission to require transmission providers to update their rates to reflect the new conditional firm service revenues and to report to the Commission annually any revenues from this service.

Commission Determination

581. The Commission affirms the decision in Order No. 890 to require transmission providers to provide planning redispatch and conditional firm service subject to a biennial reassessment when transmission customers are unwilling to pay for transmission upgrades. We decline to adopt a longer reassessment period or altogether eliminate the reassessment feature of these services. There are legitimate circumstances under which a customer may choose not to support system upgrades, including high construction costs or a short term of service that does not merit construction. Balanced against these customers' needs are the needs of transmission providers to reliably provide service and of other customers to continue using their own firm transmission rights. Adopting a two year reassessment period appropriately balances these various interests.

582. The Commission did not, as AWEA suggests, limit the term of the reassessment service. A customer taking planning redispatch or conditional firm service subject to reassessment could receive an unlimited term of service, with the transmission provider reassessing every two years the redispatch required to keep the service firm or the conditions or hours under which the transmission provider may conditionally curtail the service.[230]

583. We disagree with EEI and Southern that customers supporting transmission upgrades should be subject to the biennial reassessment. In Order No. 890, the Commission required the specification of unchanging conditions in a transmission service agreement for a customer willing to pay for upgrades.[231] Customers agreeing to take service under this bridge product require certainty because they typically are financing and constructing new resources. While we recognize that a

[228] *E.g.*, Ameren, NRECA, and Southern.

[229] *Citing* Order No. 890 at P 1601.

[230] We clarify in response to EEI that conditional firm and planning redispatch customers should pay for the costs of conducting their individual biennial reassessments.

[231] *See id.* at P 980.

transmission provider may need to incorporate a larger margin of risk into the analysis of conditions when a customer has agreed to pay for upgrades that will not be brought online for several years, we do not believe that this will most often be the case. We require transmission providers to study the conditions for bridge service as they would their own use of a similar service used prior to the completion of transmission upgrades. Only those transmission providers using large margins of risk in evaluating the acquisition or construction of their own new resources with long transmission construction lead times should apply large margins of risk to the study of the conditional firm service for a customer that agrees to pay for upgrades.

584. We agree with Southern that customers paying for upgrades have priority access to the capability created by those upgrades, up to the point of the amount of transmission service requested. To do otherwise would create disincentives for transmission customers later in the queue to pay for upgrades because upgrades must necessarily be sized to accommodate all earlier-queued customers. We note, however, that any capacity created in excess of the service request should be allocated to those planning redispatch and conditional firm customers earlier in the queue, based on their order in the queue.

585. We also agree with MidAmerican that a transmission provider's waiver of a reassessment for conditional firm or planning redispatch service does not constitute a waiver of all reassessments for the duration of the service, unless explicitly agreed to by the transmission provider. We reiterate, however, that only one reassessment may be performed in each two-year period of service. We also affirm that any waiver must be granted for similarly situated service, which would include conditional firm or planning redispatch service that is limited because of the same constraints or general system limitations. Such a waiver would be an act of discretion that must be posted on OASIS. Waiver of the reassessment presents an opportunity for discrimination among classes of customers on the part of the transmission provider and posting will provide eligible customers with an indicator of how often conditions or redispatch requirements have been reassessed. Transmission providers are directed to develop uniform OASIS posting standards, in coordination with NAESB, for transmission providers to post information regarding waivers of the biennial reassessment for planning redispatch and conditional firm service.

586. We reiterate in response to E.ON U.S. that both the transmission provider and reliability coordinator play a role in ensuring that reliability is maintained when a customer uses third-party provided planning redispatch.[232] Customers are allowed to use their own or third-party resources to secure planning redispatch services in lieu of or in addition to service from the transmission provider, provided that the arrangements are sufficiently detailed and coordinated with the transmission provider to ensure that reliability is maintained. This would entail review of redispatch plans submitted by customers, coordination between the transmission provider and reliability coordinator, and signaling third party generators when the redispatch is needed. The Commission made clear in Order No. 890 that it would be the customers' ultimate responsibility to ensure that any technical arrangements required by the reliability coordinator are in place in order to maintain reliability.

587. With regard to the conditional firm option, we continue to require that transmission providers study and offer service based on both system conditions and annual curtailment hours. The Commission introduced the concept of conditional curtailment based on system conditions in its request for supplemental comments issued on November 15, 2006. MidAmerican and other industry participants were therefore provided adequate notice and opportunity to comment on the potential for the Commission to expand the scope of the required offerings for conditional firm service. Upon review of these comments, the Commission allowed transmission providers to determine system conditions and conditional curtailment hours through different means, implicitly recognizing that system conditions are not exactly interchangeable with conditional curtailment hours.[233] Modeling of conditional curtailment hours entails difficulties beyond those encountered in modeling ATC. Transmission providers have therefore been granted flexibility in making these determinations and are allowed to use an additional risk factor in calculating conditional hours.[234] In light of the flexibility provided to transmission providers, we reject as unsupported petitioners' requests to eliminate or limit the requirement to offer conditional firm service based on the number of hours in which service may be conditional.[235]

588. In Order No. 890, the Commission allowed transmission providers to add a risk factor to their calculation of annual curtailment hours to account for forecasting risks. We decline to clarify the level of this risk factor as E.ON U.S. requests. Transmission providers need flexibility in modeling these conditions and we will not specify a level of appropriate risk factor to apply. We note however that E.ON U.S. lists events that should not be evaluated in such analysis. Car accidents, hurricanes, ice storms or other unexpected events that require curtailment of firm transmission customers taking service over a certain path should not impact the number of non-firm curtailments of conditional firm service.

589. We disagree with MidAmerican's characterization of curtailment based on system conditions as requiring automatic or immediate operator response. Transmission providers, especially those with systems susceptible to rapid voltage collapse and cascading outages, should manage these situations as they would manage any other emergency. The ability to conditionally curtail conditional firm service is not meant to address system emergencies, but rather address system conditions such as congestion on a line or flowgate, system load levels or the outage of a specific line or generator. We affirm the decision in Order No. 890 to require transmission providers to offer eligible customers seeking conditional firm service a choice between conditional curtailment based on specified system conditions or annual hours.

590. We clarify in response to Constellation and EPSA that, when a transmission provider is evaluating its continued ability to provide conditional firm service during a biennial reassessment, the transmission provider is not limited to the specific conditions previously agreed to by the transmission customer in the initial service agreement or a prior reassessment. The purpose of the biennial reassessment is to allow the transmission provider to adjust the conditions or number of hours during which conditional firm service will be conditional in order to ensure that continued provision of the service does not impair reliability. Thus, the Commission does not impose upon the transmission provider the obligation to plan its system to keep firm the part

[232] *See id.* at P 1004–07.

[233] *See id.* at P 1065–67.

[234] *See id.* at P 1067.

[235] We decline requests to extend the date for implementing conditional firm service, which has already passed.

of the conditional firm service that is firm when service was initiated. Although this may increase (or decrease) the number of hours in which service is conditional, the transmission provider may not entirely terminate service to the conditional firm customer.

591. We affirm our decision to assign conditional firm service the same curtailment priority as secondary network service for periods when the service is conditional. EEI's argument that customers use secondary network service to meet the reliability needs of their loads is inapposite. Secondary network service is a non-firm service for which requests are made in the same timeframe as other non-firm service.[236] While the Commission recognized that network customers may use secondary network service on an ''as available'' basis to meet peak native load, and in this way meet the reliability needs of loads, this is not the purpose of secondary network service. Network customers that rely upon secondary network service to meet their peak native load are already lessening the reliability of their service by taking non-firm service. The fact that conditional firm service will compete with secondary network service when curtailments are ordered is irrelevant.

592. We agree with petitioners that the NAESB rules regarding tagging do not allow a transmission provider to change the tag of a transmission customer. That is why, in Order No. 890, the Commission directed transmission providers to coordinate with other transmission providers in their regions to develop their own business practices to implement the tagging and tracking of conditional firm service.[237] Upon consideration of petitioners' concerns, we grant rehearing to require transmission providers, in coordination with NERC and NAESB, to develop within 180 days of publication of this order in the **Federal Register** a consistent set of tracking capabilities and business practices for tagging for implementation of conditional firm service. We agree with petitioners that a consistent set of practices followed by the industry will reduce transmission provider discretion and bring uniformity in implementing conditional firm service. In the interim, the existing business practices of each transmission provider for tracking and tagging conditional firm service shall remain in effect.

593. We decline to generically waive potential penalties for violations of NERC reliability standards due to implementation of conditional firm service, as Southern suggests. Southern has not provided enough information to allow us to determine whether its implementation of conditional firm service will actually cause violations of NERC planning criteria. Transmission providers are able to incorporate the specifics of a conditional firm service agreement in their base models to differing degrees, depending on the flexibility of different models and the assumptions used in modeling the service. Therefore, incorporation of conditional firm service into the base case of models need not cause overloads under N–1 conditions. Under the Commission's regulations, if Southern believes a conflict exists between its implementation of the conditional firm option and any of NERC's reliability standards, it must bring that conflict to the attention of the Commission, the Electric Reliability Organization and the relevant Regional Entity for resolution. Pending resolution of the matter, a transmission provider must continue to comply with Order No. 890 and provide conditional firm service.

594. Finally, we reject as unnecessary TDU Systems' request to require separate annual reporting of conditional firm service revenues. We also decline to generically require all transmission providers to address potential updates to transmission rates as a result of providing conditional firm service. TDU Systems has not justified treating these revenues differently than other long-term firm point-to-point revenues.

(2) Pricing of Planning Redispatch

595. The Commission determined that customers taking long-term point-to-point service with planning redispatch will have the option of paying either (i) the higher of (a) actual incremental costs of redispatch or (b) the applicable embedded cost transmission rate on file with the Commission or (ii) a fixed rate for redispatch to be negotiated by the transmission provider and customer and subject to a cap representing the total fixed and variable costs of the resources expected to provide the service. If the customer selects the higher of incremental cost or the embedded-cost rate, the transmission provider must calculate the incremental costs of redispatch monthly and charge the higher of redispatch or the embedded cost rate each month.

596. For purposes of calculating planning redispatch charges, incremental costs must include fuel or purchase power costs caused by ramping up generator(s) at the point of delivery and ramping down generator(s) at the point of receipt. Where applicable, transmission providers also may specify other incremental costs for inclusion in the monthly actual incremental costs, including opportunity costs and purchased power costs, provided that identification and derivation of these costs is included in the service agreement. All information necessary to calculate and verify opportunity costs must be made available at the request of the transmission customer.[238]

Requests for Rehearing and Clarification

597. Several petitioners argue that customers choosing planning redispatch should pay the cost of transmission service and the cost of redispatching generation.[239] These petitioners generally maintain that the redispatch of generators merely reallocates use of existing transmission capability without creating any new thermal transmission capacity. EEI and Progress contend that planning redispatch takes away firm transmission capacity from network customers and the transmission provider's native load and gives that capacity to a new point-to-point customer, without any corresponding increase in TTC. Southern notes that customers agreeing to third-party provided planning redispatch will pay both the embedded transmission rate to the transmission provider and the redispatch rate charged by the third-party generator. EEI and Southern contend that the pricing of planning redispatch should be aligned with the price of reliability redispatch and the pricing for third-party provided redispatch, arguing that different cost recovery for similarly situated generators is unduly preferential.

598. EEI also argues that the Commission's prohibition against recovery of both the incremental cost of transmission upgrades and the embedded cost of transmission service from the same customer has a different impact on the transmission provider's ability to recover its cost of service than does the prohibition against the recovery of the costs of planning redispatch and the costs of the

[236] *See id.* at P 1606.

[237] *See id.* at P 1077. We clarify that transmission providers may determine the season, month and hour for changing the priority of tags for customers taking the annual hourly conditional firm option.

[238] Although a transmission provider is not required to contract with a third party to provide planning redispatch, if it does so then the customer would be obligated to pay the purchase power costs, including any reservation charge for the power. Any flow-through of purchase power costs must be negotiated between customers and transmission providers in a stand-alone agreement if the transmission provider agrees to make purchases on the customer's behalf.

[239] *E.g.*, Ameren, EEI, Progress, Southern, Washington IOUs, and Xcel.

transmission system. When a transmission provider constructs additional transmission capacity to serve a new customer, EEI states that the transmission provider recovers the entire cost of its transmission system and its new facilities and that the only question is how those costs should be allocated between new and existing customers. EEI contends that the pricing for planning redispatch leaves the transmission provider unable to recover additional costs associated with the service.

599. Southern argues that customers will receive two distinct services and should be charged for both according to cost causation principles. Southern asserts that the Commission's pricing policy for planning redispatch service results in an uncompensated taking of the utility's property by providing no compensation for either the transmission or the generator-supplied redispatch service. Southern concludes that the rate for planning redispatch cannot be just and reasonable because the transmission provider will provide part of the service for free. E.ON. U.S. similarly argues that LSEs should have the opportunity to recover actual fuel costs since those costs are directly attributable to the service provided to the redispatch customer. Ameren asks the Commission to clarify that all costs, including lost opportunity costs will be recovered in order to avoid penalizing the generator and harming native load customers.

600. EEI argues that the Commission's rationale for prohibiting the recovery of both lost opportunity costs and the cost of transmission service in a pre-open access environment is inapplicable to the situation that transmission providers face when they must redispatch generating resources to create transmission capacity that would otherwise be unavailable.[240] According to EEI, the situation in *Penelec*, in which the utility was seeking compensation for the potential loss of future imports of non-firm energy, is inapposite to the planning redispatch requirement, in which the customer's request for firm service has priority over the transmission provider's non-firm use of the system.

601. If the Commission does not allow recovery of the costs of both transmission service and the cost of redispatching generation, EEI and Southern ask the Commission to clarify rate treatment for the planning redispatch service. They argue that the long-term point-to-point reservation that employs planning redispatch should not be included in the divisor of a transmission provider's rate calculation. Instead, Southern argues that generation-related payments associated with the redispatch should be treated as a revenue credit to off-set native load customers' fuel adjustment clause and transmission revenues from the planning redispatch service should be included in the numerator as a revenue credit. EEI contends that transmission providers should be permitted to make a rate design change through amendments to their formula rates or in a general or single rate case filing.

Commission Determination

602. The Commission affirms the decision in Order No. 890 not to adopt "and" pricing for planning redispatch service. In Order No. 890, the Commission explained that planning redispatch differs from reliability redispatch in that planning redispatch service creates additional transmission capacity[241] and reliability redispatch allows customers to avoid real-time curtailments.[242] It is appropriate for customers to pay the embedded cost of transmission and the cost of third-party redispatch because third parties cannot recover transmission revenues for the additional transmission capability created by their redispatch. Thus, different cost recovery for third party, network and transmission provider resources providing redispatch is not unduly preferential.

603. While we agree that planning redispatch does not create new thermal capacity equivalent to grid expansion, we disagree with EEI and Southern that planning redispatch does not create additional transmission capability and associated revenues for the transmission provider. When a transmission provider plans to redispatch its generation resources in order to provide previously unavailable firm point-to-point service, it does not and should not take firm service away from network and native load customers. The transmission provider continues to provide firm service to network and native load customers and receives its revenue requirement to serve those customers. The transmission provider also adds another long-term firm point-to-point service agreement and receives its embedded cost transmission rate for that service, which it would not have received but for providing the planned redispatch of its resources.

604. The pricing of planning redispatch service does not violate cost causation principles or amount to an uncompensated taking from utilities. Transmission providers will receive on a monthly basis the higher of the cost of redispatching their generators or the revenues for transmission service that they would not have received but for the redispatch. Transmission providers do not provide the redispatch of their generation for free, as Southern contends, nor do they lose the opportunity to recover actual fuel costs, as E.ON U.S. suggests. If the monthly embedded-cost transmission rate is lower than the monthly costs of redispatching resources, including actual fuel costs, the higher monthly redispatch costs may be recovered.

605. We will not allow "and" pricing of planning redispatch service, which would result in overcompensation of transmission providers and violate the Commission's long-standing opportunity costs pricing policy announced in *Penelec*. In Order No. 888, the Commission affirmed the rationale in *Penelec* for allowing utilities to charge opportunity costs in an open access environment.[243] In Order No. 888–A, the Commission specifically concluded that opportunity cost pricing is appropriate for costs that arise from a transmission provider having to reduce its off-system sales to avoid a transmission constraint and reiterated that off-system sales can only be made pursuant to the point-to-point provisions of the *pro forma* OATT.[244] The Commission also affirmed that "and" pricing is not appropriate for planning redispatch service.[245] EEI's assertion that *Penelec* is not applicable in a post-open access world is a collateral attack on Order Nos. 888 and 888–A.

606. Order No. 888 provided that revenues from direct assignment of redispatch costs must be credited to the costs of fuel and purchased power expense included in the transmission provider's wholesale fuel adjustment

[240] *Citing Pennsylvania Electric Company*, 58 FERC ¶ 61,278 at 62,873, *reh'g denied*, 60 FERC ¶ 61,034 (1992), *aff'd sub nom. Pennsylvania Electric Co.* v. *FERC*, 11 F.3d 207 (D.C. Cir. 1993) (*Penelec*).

[241] *See* Order No. 890 at P 1029 (citing Order No. 888–A at 30,267). In Order No. 888–A, the Commission began its discussion of the redispatch obligation and redispatch pricing by explaining 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." *See* Order No. 888–A at 30,267. Because a network customer cannot add new transmission upgrades on its own to the transmission provider's system, the Commission was necessarily referring in this statement to the planning redispatch obligation.

[242] *See* Order No. 890 at P 1028.

[243] *See* Order No. 888 at 31,739.

[244] *See* Order No. 888–A at 30,265, n.261.

[245] *Id.*

clause.[246] We therefore clarify that, in months in which generation-related payments are collected for planning redispatch, these payments should be treated as a revenue credit to off-set native load customers' fuel adjustment clause. In months in which the embedded cost rate of transmission is collected for planning redispatch, these revenues should be included in the numerator of the rate calculation as a revenue credit. For most planning redispatch service, we believe that there will likely be at least one month a year when the actual incremental cost of redispatch is higher than the embedded cost rate. For this reason we believe it is appropriate for transmission providers to treat transmission revenues from planning redispatch service consistent with the rate treatment for revenues from short-term transmission reservations. To the extent necessary, a transmission provider may propose in an FPA section 205 filing any rate design change that may be necessary through an amendment to its formula rate or in a general or single rate case filing.

(3) Rollover Rights

607. The Commission found in Order No. 890 that rollover rights are appropriate for point-to-point service that is provided using planning redispatch or conditional firm options and that would otherwise be eligible for rollover rights. The transmission provider, however, will continue to have a right to review the conditions or redispatch requirements every two years.

608. The Commission determined that a conditional firm customer opting to roll over will retain a priority claim to the portion of its service that is firm. The Commission qualified this statement by providing an example: if a five-year conditional firm service initially has a 100-hour annual cap on curtailments, but the cap is later reassessed at 150 hours, the rollover right would continue to give the customer first call on all but the 150 hours as against all other subsequent requests for firm service.

Requests for Rehearing and Clarification

609. TDU Systems and Ameren argue that the Commission erred in allowing rollover rights for conditional firm service that is subject to biennial reassessment. TDU Systems and Ameren argue that allowing rollover for this service is inconsistent with other requirements of Order No. 890 that limit conditional firm service to the shorter term service if customers do not agree to pay for upgrades. TDU Systems contend that allowing rollover rights for customers taking conditional firm service creates a continued opportunity for transmission customers to free ride on transmission capacity built and paid for by others. Ameren maintains allowing rollover rights for conditional firm agreements will increase uncertainty in modeling and will decrease the incentive to upgrade the transmission system.

Commission Determination

610. The Commission affirms the decision in Order No. 890 to provide rollover rights to conditional firm point-to-point service that otherwise qualifies for rollover rights. We disagree that granting rollover rights to conditional firm customers is inconsistent with statements in Order No. 890 that customers not willing to pay for upgrades should have their service limited. Customers taking conditional firm service subject to reassessment take the risk that the firmness of their service will deteriorate with every biennial reassessment. These customers are not free riding on the transmission grid, but rather are taking less than firm service and making a contribution to the embedded costs of the grid by paying the long-term firm transmission rate. Allowing rollover will not increase uncertainty in modeling the service, as Ameren contends, because transmission providers will still be able to perform biennial reassessments every two years for those conditional firm customers not willing to pay for upgrades.

611. We also disagree that granting rollover rights to conditional firm customers decreases incentives to expand the grid. Even without rollover rights, conditional firm customers wishing to continue their service could simply submit additional requests for service, in response to which the transmission provider would identify the limiting conditions for continued service. Granting rollover rights to longer-term conditional firm customers allows these customers to keep their place in line ahead of others seeking conditional firm service in recognition of the longer-term commitment they made to the transmission provider. Ameren's concern, then, is with the underlying requirement to offer conditional firm service, which we affirm above.

(4) Use of the Conditional Firm Option in Designating Network Resources

612. In Order No. 890, the Commission concluded that conditional firm point-to-point service is sufficiently firm to support the designation of network resources imported from other control areas. The Commission concluded that the conditional firm option only affects the transmission of the resource to the network, not the interruptibility of the generating resource itself, and the transmission may not be interrupted for reasons other than reliability.

Requests for Rehearing and Clarification

613. Several petitioners object to allowing conditional firm service to be used to support an off-system designated network resource.[247] EEI and Progress argue that allowing designation of such resources would adversely impact system reliability. EEI asserts that some customers may take conditional firm service that is curtailable in all summer months, not just 10 to 20 hours a year. EEI contends that conditional firm service presents the possibility that the supply of energy from a generator may be interrupted for a substantial period of time, well in excess of the time for an interruption due to a forced outage or maintenance outage. EEI asserts that this less reliable service to serve load will not only impact the conditional firm customer's supply of energy, but could affect other network customers and native load customers.

614. Duke requests clarification that off-system conditional firm-supported resources may qualify as designated network resources only if the network customer clearly specifies in its Network Integration Transmission Service Agreement specific backup arrangements, such as adequate reserves. Duke also asks the Commission to clarify that a transmission provider need not undertake provider-of-last-resort obligations to any network customer that elects to designate a network resource supported by conditional firm service.

615. PJM asks the Commission to clarify that Order No. 890 does not require it to accept conditional firm service as sufficient to qualify external generating resources as capacity resources for purposes of PJM's Reliability Pricing Model (RPM). In order to qualify as a capacity resource, PJM asserts that an external unit must have a firm path to load that is available year-round, particularly during high-level periods when adjacent control areas both are experiencing system stresses.

[246] *See* Order No. 888 at 31,740.

[247] *E.g.*, Duke, EEI, Progress, and TDU Systems.

Commission Determination

616. The Commission affirms the decision in Order No. 890 to allow the designation of off-system resources supported by conditional firm point-to-point service.[248] It is appropriate to allow conditional firm service to support the designation of network resources because the conditional firm option only affects the transmission of the resource to the network, not the interruptibility of the generating resource itself. Conditional firm service satisfies the requirement that the delivery of the resource to the network to be non-interruptible because conditional firm transmission service is curtailable only for specific reliability reasons, not for economic reasons.

617. We acknowledge that conditional firm service may have conditions that apply for most of the peak periods of a month or season. This does not mean that such service will necessarily impact the reliability of the transmission provider's system. The Commission declines Duke's request to require a network customer with a designated off-system resource supported by conditional firm service to obtain reserves or backup resources to cover the periods when the resource supported with conditional firm point-to-point transmission service might not be delivered. It is not the responsibility of the transmission provider to ensure that the network customer has sufficient resources to meet its load.

618. Whether or not off-system resources supported by conditional firm service may serve as a capacity resource under PJM's RPM is governed by the relevant RPM rules adopted by PJM, which were not addressed in Order No. 890.

c. Proposals for Transparent Redispatch

619. In Order No. 890, the Commission rejected requests to expand the transmission provider's real-time redispatch obligations to incorporate third-party bids for redispatch or otherwise require reliability redispatch to be offered to point-to-point customers. The Commission concluded that the provision of reliability redispatch only to network customers did not constitute undue discrimination because, unlike point-to-point customers, network customers are required to make their generation resources available to the transmission provider to provide reliability redispatch to maintain the reliability of both native load and network service. The Commission also determined that mandatory inclusion of third party offers to redispatch is not necessary to remedy undue discrimination because, unlike the transmission provider, third party generators are under no obligation to make their resources available to provide redispatch.

620. The Commission did, however, require that transmission providers post certain redispatch cost information associated with the existing redispatch services that must be provided under the *pro forma* OATT. The Commission concluded that providing customers with additional transparency and greater information regarding the cost of congestion will facilitate their consideration of planning redispatch options, which in turn will provide for more efficient use of the grid. To that end, the Commission directed each transmission provider to post on OASIS its monthly average cost of redispatch for each internal congested transmission facility or interface over which it provides planning redispatch or reliability redispatch under the *pro forma* OATT. In addition, to demonstrate the range of redispatch costs each month, the Commission directed transmission providers to post a high and low redispatch cost for the month for each of these same transmission constraints.

621. Transmission providers must post internal constraint or interface data for the month if any planning redispatch or reliability redispatch is provided during the month, regardless of whether the transmission customer is required to reimburse the transmission provider for those exact costs. Thus, if the transmission customer pays for planning redispatch pursuant to a negotiated fixed rate, the transmission provider is required to post and calculate the monthly average redispatch costs and the high and low costs in the month even though the transmission provider will bill the customer the fixed rate. The same posting requirement applies if the customer is paying a monthly ''higher of'' rate. The Commission concluded that the relevant reliability redispatch costs for posting purposes are those costs the transmission provider invoices network customers based on a load ratio share pursuant to section 33.3 of the *pro forma* OATT.[249] The transmission provider must post this data on OASIS as soon as practical after the end of each month, but no later than when it sends invoices to transmission customers for redispatch-related services. The Commission directed transmission providers to work in conjunction with NAESB to develop this new OASIS functionality and any necessary business practice standards.

Requests for Rehearing and Clarification

622. Ameren argues that the redispatch cost posting requirement is unreasonable because it creates a substantial new burden for transmission providers without creating offsetting benefits for transmission customers. Ameren maintains that the Commission failed to assess the benefits and the burdens of the redispatch costs posting requirement. Ameren also maintains that this information will not provide any value to the transmission customer in anticipating redispatch costs since certain factors embedded in the calculation of these costs, including fuel, will vary greatly over time. Ameren concludes that existing requirements under the *pro forma* OATT are all that is necessary to provide transparency for the service.

623. Progress Energy requests clarification that reliability redispatch costs need only be posted if the transmission provider invoices network customers for those costs. Progress Energy states that Order No. 890 contains language that could be read to require the posting of reliability redispatch costs even if network customers are not invoiced for those costs, notwithstanding the Commission's statement that the relevant reliability redispatch costs for posting purposes are those costs the transmission provider invoices network customers.[250] Progress Energy concludes that it would be unduly burdensome and serve no regulatory purpose to require transmission providers to post reliability redispatch costs when they are not invoicing their network customers for these costs.

624. Entergy requests clarification that, when redispatch charges are calculated and charged on a system average basis, only the average costs for the system for the month need be posted. Entergy states that its new weekly procurement process will provide customers a greater opportunity to obtain transmission service by paying redispatch costs, as determined through the optimization models in the weekly procurement process. These optimization models will not calculate redispatch costs for each specific constrained facility on Entergy's system.

[248] *See* Order No. 890 at P 1091.

[249] Order No. 890 provided that the transmission provider need not perform new calculations of out-of-merit redispatch costs; rather the reliability redispatch invoices should form the basis of information from which the transmission provider determines monthly average reliability redispatch costs.

[250] *Citing* Order No. 890 at P 1162, n.707.

Entergy states it would incur additional burdens if required to separately calculate these costs to meet the Order No. 890 requirement to post redispatch costs by each constrained facility.

Commission Determination

625. The Commission affirms the decision in Order No. 890 to require transmission providers to post on OASIS monthly average redispatch costs for each internal congested transmission facility and interface over which planning redispatch or reliability dispatch are provided under the *pro forma* OATT. We disagree with Ameren that this creates a substantial new reporting burden for transmission providers. The information to be posted is readily available to transmission providers from the invoices used to charge network customers, in the case of reliability redispatch costs, or calculations that the transmission provider performs to bill for planning redispatch services. The only added burden involves posting those previously calculated costs and calculating averages in order to mask commercially sensitive information. This additional averaging step was instituted to address concerns raised by Ameren and others about release of proprietary or confidential market information.[251] Although we do not believe this averaging step to be unduly burdensome, Ameren or any other transmission provider may propose a variation from the *pro forma* OATT to allow for posting of actual billing data if the transmission provider believes it is too burdensome to average this data prior to posting.

626. Any minimal burden imposed on transmission providers by the redispatch cost posting requirement is offset by the benefits of providing customers with fairly current information regarding which facilities are congested each month and the average costs of redispatch over those facilities.[252] This information has previously been provided only to customers receiving specific redispatch services. While redispatch costs incurred by customers in the present do not always correlate with future redispatch costs, a fact recognized by the Commission in Order No. 890,[253] more information on the currently provided redispatch could be invaluable to a potential or current customer evaluating different generation and transmission options. A reporting requirement that allows customers to identify constraints and the monthly average costs of relieving those constraints provides a benefit to customers that outweighs the small monthly posting burden.

627. To the extent necessary, we clarify in response to Progress Energy that transmission providers that do not calculate and charge separate reliability dispatch charges to its network customers have no obligation to report monthly redispatch costs for those services. The posting obligations adopted in Order No. 890 were designed so that transmission providers could post redispatch cost information based on data already calculated for another purpose, including customer invoices for reliability dispatch and the determination of charges for the monthly ''higher of'' rate for planning redispatch.[254] If redispatch costs are calculated and charged on a system-wide basis rather than for each constraint on the system, the transmission provider has no obligation to perform new calculations to estimate the redispatch costs for each constraint on its system. We therefore agree with Entergy that, in the described situation, only the average costs for the system for the month, including the highest and lowest system average redispatch costs in an hour for the month, need be posted.

d. Other Requested Service Modifications

628. The Commission rejected requests to adopt other new services or modifications to existing services beyond those reforms adopted in Order No. 890. Among other things, the Commission declined to require transmission providers to offer a dynamic scheduling service for loads and resources that are located in different transmission providers' areas. The Commission stated that transmission providers seeking to provide this or additional new services may submit an FPA section 205 filing to propose modifications to their OATT, which would be considered on a case-by-case basis.

Requests for Rehearing and Clarification

629. TAPS requests that the Commission require transmission providers to include provisions in their OATTs that would permit a transmission dependent utility with loads and resources in multiple control areas to consolidate them into a single control area via dynamic scheduling. TAPS states that a control area utility with remote generation and/or load has the option to use a pseudo-tie to import generation into its control area. TAPS argues that transmission dependent utilities should have comparable options priced at the transmission provider's cost. TAPS contends that leaving transmission dependent utilities in the position of having to negotiate with the transmission providers for this option will leave them exposed to unjust and unreasonable and unduly discriminatory imbalance pricing. TAPS also argues that changes to the OATT to allow for dynamic scheduling should not disturb already existing dynamic scheduling agreements that have been successfully negotiated by transmission dependent utilities.

Commission Determination

630. The Commission denies rehearing of the decision in Order No. 890 to not mandate a dynamic scheduling service in the *pro forma* OATT. Dynamic schedules and pseudo-ties are both services that involve metering, telemetry, computer software, hardware, communications, engineering and administration. Each service is crafted to meet the unique needs of each customer, typically requiring the cooperation and services of at least two control areas as well as contractor-providers of the components of the services. Comparability does not require the transmission provider to undertake these negotiations on behalf of its network customers. The unique, customer-specific nature of these services are more properly arranged by negotiation between the relevant parties rather than standardized in the *pro forma* OATT. However, to the extent a transmission provider currently accepts telemetered generation schedules for its native load, the transmission provider must accept such schedules from its network customers on a comparable basis.

631. The Commission is also concerned that the mandatory cost-based provision of pseudo-ties could allow transmission customers to cherry-pick among transmission providers based on differences in service, including ancillary service costs, and could cause insurmountable planning and reliability problems for transmission providers. Under a pseudo-tie, the control area receiving the new load or generation signal assumes responsibility for ensuring that the load is properly balanced moment-

[251] *See id.* at P 1150.

[252] *See id.* at P 1163.

[253] *See id.* at P 1159.

[254] The posting requirement for the newly instituted negotiated fixed rate pricing option for planning redispatch is an exception. If a transmission provider chooses to negotiate a fixed rate for planning redispatch, it must determine and report the redispatch costs for providing that service even though it might not otherwise need to calculate these costs.

to-moment, for planning for the load, and for providing various other ancillary services including energy or generator balancing service. We decline to impose unlimited planning, reliability and ancillary service requirements on transmission providers by forcing them to accept any load or generator that seeks to move to their systems. We are encouraged, however, by the increased availability of pseudo-ties and dynamic schedules in the industry. TAPS and others have been able to secure dynamic scheduling agreements on a negotiated basis, and we do not intend to disrupt those agreements in this proceeding.

2. Rollover Rights

632. In Order No. 890, the Commission revised the rollover provision in section 2.2 of the *pro forma* OATT, which grants an ongoing right to firm transmission customers to renew or ''rollover'' their contracts. Under Order No. 888, transmission customers were allowed to rollover contracts with a minimum term of one year, provided that they provide notification of the rollover no later than 60 days prior to expiration of their service agreements. The Commission concluded that this provision was no longer just and reasonable, extending the minimum term necessary to qualify for a rollover to five years and the notice deadline to one year. Thus, a transmission customer must agree to another five-year contract term or match any longer term competing request within one year of expiration of its five-year service agreement in order to be eligible for a subsequent rollover. The Commission stated that this reform will become effective for each transmission provider upon acceptance of the transmission provider's compliance filing containing a coordinated and regional planning process that satisfies the requirements of Order No. 890.

633. The Commission declined to eliminate the requirement that an existing transmission customer match competing offers as to term and rate in order to roll over its service. The Commission also continued to require rollover restrictions to be based only on reasonable forecasts of native load growth or preexisting contracts that commence in the future. The Commission affirmed that any restrictions on a customer's rollover rights must be included in the initial transmission service agreement.

a. Five-Year Minimum Contract Term

Requests for Rehearing and Clarification

634. APPA, NCEMC, TAPS, and TDU Systems state a general concern that, under current market conditions, some transmission customers may be unable to obtain power supplies of a term and firmness required to support a five-year firm transmission agreement. Each of these petitioners note that FPA section 217(b)(4) requires the Commission to exercise its authority ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy [their] service obligations * * * and enables load-serving entities to secure firm transmission rights * * * on a long-term basis for long-term power supply arrangements made, or planned to meet such needs.'' These petitioners argue that the Commission's rollover reforms impede, rather than facilitate, the ability of LSEs to secure firm transmission rights on a long-term basis to meet their service obligations.

635. TDU Systems and NCEMC suggest that implementation of the five-year minimum contract requirement for obtaining rollover rights be conditioned on a demonstration that the relevant generation markets can support five-year power supply contracts. TDU Systems state that the Commission misinterpreted its initial comments on this issue as a request to require transmission providers to engage in the business of procuring supplies for their transmission customers. TDU Systems explain that they only requested that the Commission determine whether market conditions are such that transmission customers themselves may procure five-year generation contracts, such as by using the Herfindahl-Hirshman Index as a tool for determining the competitiveness of the relevant generation markets.

636. TAPS argues that, where transmission constraints exist, a customer could be forced to remain with an incumbent supplier or face the loss of its rights to continued use of the grid. NCEMC expresses similar concerns, arguing that on constrained systems the rollover reforms significantly increase the potential for market power abuse. NCEMC contends that an incumbent generator can limit an LSE's access to rollover rights by simply refusing to offer five-year power supply contracts.

637. TAPS further argues that these concerns are not adequately addressed by other reforms adopted in Order No. 890, as suggested by the Commission. TAPS contends that many of these reforms, such as those involving conditional firm and planning redispatch, redirects, and capacity reassignment, apply only to point-to-point service, not network service. TAPS argues that reforms increasing the accuracy of ATC calculations will not help if the calculation results in zero ATC and that coordinated transmission planning will only help if it results in actual construction of transmission expansions. APPA similarly argues that any benefits from increased coordination in transmission planning will take some time to develop.

638. APPA and TAPS contend that the Commission should condition the requirement of a five-year minimum contract term to obtain a rollover right on allowing customers that enter into such contracts the flexibility to modify receipt points and resource designations as their power supply needs change. TAPS argues that the Commission should grant certain clarifications regarding network customers' rollover rights, in recognition of the fact that such customers pay for the transmission provider's whole system. First, TAPS asks the Commission to make clear that the customer is not restricted to its existing supplier by requiring transmission providers to flexibly accommodate changed resources so that network customers have the benefit of continued use of the transmission system planned on their behalf and paid for on a load ratio share basis. Second, TAPS asks the Commission, at a minimum, to affirm the existing requirement that a new resource should not be rejected as a rollover simply because it is not identical to the prior resource, *i.e.*, that a rollover must be allowed unless there is a ''substantial change'' in the direction of flows. Third, TAPS requests that the Commission require the transmission provider, at least until compliance with planning-related reforms, to accept a network customer's timely designated network resource, even if necessary through redispatch (with costs shared on a load ratio basis), unless the transmission provider can show that the customer's supply choice was not reasonably foreseeable. Alternatively, TAPS argues that the Commission should require cost-based sales to the trapped embedded transmission dependent utility.

639. TDU Systems state that rollover rights should be allowed unless there is a substantial change in power flows and argues further that transmission providers should be required to permit rollover of a network customer's resource if the transmission provider would accord itself rollover of the resource if it served the transmission provider's load. TDU Systems argue that

transmission providers commonly treat their entire transmission systems as single sinks and apply redispatch in order to accommodate rollover of their own network resources, while at the same time, they evaluate other users' rollovers of network resources non-comparably, strictly on the basis of flows to discrete load centers, without the benefit of redispatch. TDU Systems contend that this practice discriminates against network customers. AMP-Ohio asks the Commission to clarify that a network customer is permitted to roll over a portion of a long-term reservation.

640. Morgan Stanley argues that the Commission failed to address its argument that limiting rollover rights to customers with firm transmission contracts of five years in length or more establishes significant barriers to entry. Morgan Stanley contends the credit and collateral requirements to enter into a five-year commitment are much higher than those necessary to enter into a one-year deal and that this higher credit requirement could limit the variety and flexibility of the resources available to serve load. Morgan Stanley also argues that extending the minimum term to five years will result in an increase in transmission costs without any corresponding benefits to parties trying to serve load. Morgan Stanley asserts that transmission customers choosing to serve load will have to purchase more capacity than needed, which will make less capacity available for others and will increase costs to the loads served.

641. Morgan Stanley also argues that the change in rollover right policy discriminates against merchant generators, like Morgan Stanley, that do not have load linked to generation. Morgan Stanley contends that forcing a merchant generator to purchase longer-term transmission will increase its costs to build and encourage local utilities to build their own generation rather than seek competitive alternatives. Morgan Stanley repeats arguments that the lack of firm, long-term transmission reservations in the California and New England organized markets belies the Commission's findings that contract certainty is needed in order for transmission providers to appropriately plan and construct their systems.

642. Ameren similarly argues that the Commission failed to consider the effect on the markets of limiting rollover rights to contracts with a minimum term of five years, particularly with regard to markets in which utilities meet their energy needs through annual auctions or requests for proposals. Ameren contends that a one-year minimum term should be all that is necessary for a customer to roll over its service, arguing that current market conditions and the volatility in fuel prices make it undesirable for power sellers and power purchasers alike to enter into longer contracts. Ameren also questions the Commission's argument that rollover reforms are needed to improve transmission planning, arguing that the lack of transmission infrastructure demonstrates that the prior rollover policy did not in fact lead to overbuilding. Ameren asserts that there will be fewer contracts with rollover rights under the new policy and, as a result, planning and reliability will be harmed because transmission providers will only have to plan for this more limited group of contracts. At the same time, Ameren argues that the viability of the short-term market will be impaired because the ability of transmission customers to continue their service will be placed in doubt. Ameren contends that this scenario will be exacerbated in organized markets where many sales and purchases occur in short-term or spot markets. If the Commission declines to grant rehearing regarding the five-year minimum term requirement, Ameren asks the Commission to clarify that it is eliminating the requirement for transmission providers to plan their systems to accommodate transmission customers with contracts that are shorter than five years.

643. Williams suggests that the minimum term for the exercise of rollover rights should be three years, as it believes this better balances the respective rights and obligations of transmission customers and transmission providers. Williams argues that extending the minimum rollover term will result in less flexibility for transmission customers to adjust to changing market conditions and more harm to competition. Williams provides an example of a customer receiving non-firm service due to a redirected transmission service request, asserting that the customer would be ''saddled'' with non-firm service for the duration of the minimum term, notwithstanding the fact that prior to the redirect the customer contracted for firm service. Although the customer would still receive the same, non-firm service under a three-year minimum term, the shorter term enables the customer to return to the benefit of its bargain sooner and better reflects the initial intent of the parties.

Commission Determination

644. The Commission affirms the decision in Order No. 890 to limit rollover rights to contracts with a minimum term of five years. As the Commission explained in Order No. 890, the prior rollover policy was no longer just, reasonable, and not unduly discriminatory because the rights and obligations of a rollover customer no longer bore a rational relationship to the planning and construction obligations imposed on the transmission provider by the rollover rights. We continue to believe that a five-year term will ensure greater consistency between the rights and obligations of customers and the corresponding planning and construction obligations of transmission providers. While we appreciate that this reform will affect the way customers retain transmission service, other reforms adopted in Order No. 890 will mitigate the concerns of shorter-term customers, in particular the obligation for transmission providers to adopt an open, coordinated and transparent process for planning to meet the transmission needs of all customers.

645. The Commission takes seriously the concerns and allegations about the presence of generation market power and the lack of availability of long-term power contracts, and we will continue to address these issues in other contexts, in particular our market-based rate program. The purpose of our reform of the rollover policy, however, is to align the rights and obligations of the customer with those of the transmission provider, not with the availability of supplies within a market or particular commercial practices in a region. A point-to-point customer need not have a five-year power contract in order to secure a five-year transmission service contract. Similarly, it is the length of a network customer's network service agreement, not the length of the power contract supporting a network resource designation, that determines whether the customer is eligible for rollover.[255] Thus, the availability of five-year power contracts is not determinative of the ability of transmission customers to obtain rollover rights.

646. We acknowledge that entering into longer-term transmission service agreements might increase risk or reduce flexibility for some customers, including merchant generators, as they manage their power supplies and transmission contracts. Balanced against this potentially negative effect, however, are the many benefits that will flow from rollover reform. Under the prior rollover policy, a customer could secure transmission for one year and effectively require the transmission provider to plan and upgrade its system on the

[255] *See Wisconsin Pub. Power Inc. SYSTEM* v. *Wisconsin Pub. Serv. Corp.*, 84 FERC ¶ 61,120 at 61,659 (1998) (*WPPI*).

assumption the rollover right would be continually renewed. As the Commission noted in Order No. 890, it is inappropriate to require transmission providers to use finite resources to finance and construct facilities that may not be necessary, particularly in light of the difficulty of siting new transmission.[256] The prior rollover policy also harmed other transmission customers by allowing rollover customers to lock up existing capacity that could have been used by other customers. A minimum term of five years, and not a shorter period such as three years as suggested by Williams, best balances the benefits and burdens associated with our rollover policy.

647. In response to TAPS, we clarify that we did not intend in Order No. 890 to restrict the rollover right to exactly the same points of receipt and delivery as the terminating service, as this would competitively disadvantage existing customers seeking new sources of generation. As the Commission explained in Order Nos. 888 and 888–A, ''if the customer chooses a new power supplier and this substantially changes the location or direction of the power flows it imposes on the transmission provider's system, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change.'' [257] Thus, a transmission provider must allow a rollover, even where a transmission customer changes power suppliers, so long as there is no substantial change in the location or direction of the power flows imposed on the transmission provider's system. Moreover, we agree with TDU Systems that it would be inappropriate for transmission providers to treat a network customer's request for rollover to accommodate a new designated network resource differently than they treat their own new resources for their own loads. Transmission providers must permit rollover of a network resource by another user if it would accord itself rollover of the resource if it served the transmission provider's load.

648. We do not believe, however, that it is appropriate to expand the rights of rollover customers as requested by some petitioners. We therefore decline to condition the requirement of a five-year minimum contract term on allowing customers signing such agreements unlimited flexibility to modify their designated resources and receipt points as their power supply needs change within their five-year transmission service agreements. As the Commission explained in Order No. 890, such an approach is unworkable because it could result in substantial disruptions in transmission service to higher queued customers requesting long-term service over these paths.[258] The fact that network customers pay a load-ratio share of system costs does not justify granting such customers a guaranteed ability to change their service to other points without regard to other competing requests for service that may be in the queue. Without a limit on rollover customers' flexibility to modify designated resources and receipt points, neither the transmission provider nor any other customer in the queue would ever be able to rely on any study process for service, as it could be thrown into disarray by a rollover customer seeking to change its points. The only way such a system could work would be if every transmission provider constructs its system with sufficient redundancy to permit any customer to take service from any resource, which would be both impractical and uneconomic.

649. We also disagree that our reforms to rollover policy will harm planning and reliability, even if it does result in fewer contracts with rollover rights. As we note above, shorter-term transmission customers no longer eligible for rollover rights will nonetheless have access to the coordinated, open, and transparent transmission planning process required in Order No. 890, which will help ensure that transmission providers adequately and comparably plan for the transmission needs of all of their customers whether or not they have rollover rights. This is one of the reasons why the Commission conditioned the effectiveness of the rollover reforms on its acceptance of a transmission provider's Attachment K planning process in compliance with the transmission planning principles adopted in Order No. 890. By extending the minimum term for rollover rights, the Commission simply relieved transmission providers of the obligation to undertake construction on behalf of shorter-term customers that may not ultimately need the facilities.

650. We reject the suggestion that a five-year minimum is inconsistent with the requirements of FPA section 217. Limiting rollover rights to contracts with a minimum term of five-years ensures that the rollover right is used by customers with longer-term obligations to purchase capacity, benefiting all longer-term customers by limiting the ability of shorter-term customers to lock up capacity they do not intend to use and facilitating efficient planning and expansion decisions by the transmission provider. These benefits are shared by the entire class of customers to which section 217 applies.

651. In response to AMP-Ohio, we clarify that both network customers and point-to-point customers may roll over a portion of their service, provided that they will only obtain a subsequent rollover right if they agree to another five-year term, or match any longer term competing request, for that portion of capacity.

b. One-Year Notice Provision

Requests for Rehearing and Clarification

652. Duke asks the Commission to further revise the rollover notification provisions to provide for additional time for construction of new facilities in the event project upgrades and lead times have been identified. Duke argues that the Commission failed to explain in Order No. 890 why it is reasonable to expect on-system LSEs, including the transmission provider, to coordinate their resource plans with the lead-time for new transmission facilities, but it is not reasonable to expect off-system LSEs that rely upon point-to-point service to be subject to the same realities. Because an LSE that is a network customer on one system must provide sufficient and adequate notice for its transmission provider to accommodate an on-system designated network resource, Duke contends that the one-year notification requirement for rollovers means that the same LSE need not provide a neighboring transmission provider the same level of notice to accommodate a point-to-point rollover request even if related to the very same designated network resource. Duke further argues that the Commission failed to explain why the native load protection rationale that prompted adoption of the initial five-year eligibility provision should not apply with equal force to the notification provision.

653. Duke states that, in its experience, most LSEs do not wait until one year before the expiration of their contract resources to make decisions as to a replacement resource. In the event an LSE does choose to wait until one year before its current supply contract ends, Duke argues that the LSE's decision should not disadvantage native load and network customers if, as the Commission recognized, necessary transmission upgrades cannot be completed within that one-year period. Duke contends that modification of the

[256] *See* Order No. 890 at P 1233.

[257] *See* Order No. 888–A at 30,198, n.52 (citing Order No. 888 at 31,665, n.176).

[258] *See* Order No. 890 at P 1236.

one-year notice requirement is necessary to ensure greater consistency between the rights and obligations of customers and the corresponding planning and construction obligations of transmission providers, the stated goal of the Commission's rollover reforms. If the Commission is unwilling to change the one-year notice provision, Duke suggests that the Commission provide that a rollover customer's service will be conditionally firm during the period prior to the point in time when needed transmission upgrades can be completed.

654. Southern expresses a similar concern, arguing that a customer should be required to provide notice of its intent to exercise its rollover rights at the earlier of one year or the lead-time for any construction of upgrades identified by the transmission provider in the service agreement that are necessary in order to reliably exercise the rollover right. Southern contends that this requirement would be consistent with the ability of the transmission provider to place in the original service agreement limits on the customer's ability to exercise rollover rights and is needed to maintain reliability and protect the provision of service to other firm users of the transmission system, including native load.

Commission Determination

655. We affirm the decision in Order No. 890 to require customers to notify the transmission provider of their intent to exercise their rollover rights at least one year before expiration of their service agreement. We reject requests to tie the notice period to the construction lead-times for any upgrades a transmission provider may believe are necessary in order to accommodate any rolled over service along with its other service obligations. The Commission recognized in Order No. 890 that the one-year notice period is shorter than the typical planning horizon, but declined to extend the notice period to a time that coincides with the typical planning horizon or the time it takes to construct new facilities.[259] The Commission balanced the circumstances facing customers in renewing power supply contracts and the interests of transmission providers in attempting to plan their system. We continue to believe that the one-year notice provision most appropriately balances these competing interests.

656. We acknowledge that, in certain circumstances, the one-year notice period could cause the transmission provider to undertake construction of facilities that are not ultimately needed to accommodate other service obligations in light of a rollover customer declining to rollover its service. However, moving from a 60-day notice period to one year should mitigate the risk of unnecessary investments. While allowing a transmission provider to require rollover notification prior to construction of facilities (whether or not identified in the original service agreement), or treating the customer's service as conditionally firm while upgrades are completed, would further reduce this risk for the transmission provider, it also would further decrease flexibility for the transmission customer. As the Commission explained in Order No. 890, no single notice period can perfectly balance the needs of customers and transmission providers.[260] The Commission concluded that a one-year notice provision best balances the respective benefits and burdens for customers and transmission providers, and we affirm that decision here.

c. Matching Competing Requests

Requests for Rehearing and Clarification

657. APPA argues that the Commission's retention of its matching policy, requiring transmission customers to match competing requests for service as to term and rate, is inconsistent with FPA section 217(b)(4). In APPA's view, section 217(b)(4) requires the Commission to exercise its FPA authorities to assist LSEs in meeting their service obligations by securing firm transmission rights on a long-term basis. APPA contends it is contrary to Congressional intent to require LSEs that have made long-term financial commitments to the transmission system, by entering into five-year agreements, to bid against all other interested market participants in order to roll over their firm transmission rights.

658. APPA also argues that the Commission's decision to lift the price cap on reassignments of firm transmission capacity might exacerbate the situation, as it could mean that LSEs will have to bid against well-heeled financial players or marketing affiliates of the transmission provider that may be bidding for the same capacity with the sole intent of reassigning it at whatever price the market will bear. APPA contends that this would require LSEs unable to match the longer term offered (due, for example, to its inability to obtain a power supply contract of that length) to have to obtain firm transmission capacity in the reassignment market at a much higher rate. APPA argues that this, too, is inconsistent with the Commission's obligation under FPA section 217(b)(4) to enable LSEs with service obligations to obtain the long-term firm transmission rights they must have to meet those needs.

659. APPA adds that the transmission provider should have been planning for the needs of firm transmission customers with contracts that carry rollover rights throughout the term of the contract, since the stated purpose of the rollover reform is to ensure that the rights and obligations of the customer are better aligned with the planning and construction obligations of the transmission provider. APPA argues that capacity should therefore be available to meet the needs of firm transmission customers seeking to exercise their rollover rights without forcing them to ''bid on the margin'' for transmission capacity every time their contracts come up for renewal.

660. TAPS proposes what it characterizes as safeguards to prevent network customers exercising rollover rights from being significantly disadvantaged by the obligation to match point-to-point reservations. TAPS contends that a point-to-point customer, faced with a competing longer-term reservation, can simply extend the term of its point-to-point commitment to match the competing request. If the matching process applies to network service designations under a network service agreement (versus the service agreement itself), TAPS contends that the network customer would need to extend its power supply commitment in order to extend its transmission reservation to match the competing request and would not be able to resell any transmission capacity for which it could not find supplies. TAPS argues that this fails to recognize and preserve the LSE's continuing rights under FPA section 217(b)(1) to (3) to use their existing firm transmission rights, including rollover rights, and that it is inconsistent with section 217(b)(4) for the Commission to leave transmission-dependent LSEs at risk of denial of continued use of transmission to meet their service obligations.

661. TAPS therefore suggests that the Commission implement matching based on the duration of a network customer's network service agreement rather than its resource designation. Alternatively, if the Commission concludes that the network customer must extend its resource commitment (rather than just

[259] *See id.* at P 1247.

[260] *See id.* at P 1246.

its network agreement duration) to match a competing request, TAPS proposes the following modifications to the process so that the network customer is on a level playing field with competing point-to-point customers in the matching process: restrict reservations qualified to compete against a network customer's reservation to customers with long-term power contracts (even if they seek only point-to-point reservations); and provide a cut-off for competing requests that accommodates the network customer's need to extend power supply arrangements in order to match competing requests. TAPS suggests, for example, that the network customer should only need to compete with requests submitted at least three months prior to when the network customer exercises its rollover right, which would allow the network customer to structure its power supply commitments with some degree of advanced knowledge of the competing requests. TAPS also suggests that such a rolling cut-off (*i.e.*, one tied to the network customer's rollover notice) be adopted to encourage early exercise of rollover rights, thereby benefiting the planning process.

662. TDU Systems suggest that the Commission cap the matching term required to secure rollover rights to five years, arguing that a customer agreeing to pay the maximum rate allowed under the tariff for a five-year term should be assured that it will retain its rollover rights. TDU Systems contend that the increase in the minimum term from one year to five years has mitigated the need for an unlimited matching requirement by providing the transmission provider greater certainty in planning its system. TDU Systems also contend that transmission providers will not be financially harmed by capping the matching requirement at five years since competing rollover customers would be subject to price-matching as well. Finally, TDU Systems argue that the ''longer of'' matching policy is unduly discriminatory when applied to requests from transmission providers in particular, since they are able to request transmission service for unreasonable terms that no transmission customer could prudently match.

663. Ameren and Powerex propose other modifications to the matching process. Ameren proposes that customers be required to provide notice of a rollover within 15 days of a pre-confirmed competing request to prevent the customer from sitting on capacity until the end of its notice period. Powerex makes a related request to restrict the matching requirement to bona fide competing commitments to take such service, such as by requiring competing requests to be pre-confirmed or requiring the execution of contingent service contracts. Powerex contends that, without such a restriction, a customer wishing to roll over its service could be required to match requests in the queue for a longer duration that ultimately may not come to fruition. Powerex also asks that the Commission clarify that, in cases where a long-term customer that has exercised its rollover right is ''trumped'' by a longer-duration competing request for a lesser quantity, the rollover of the original request should be displaced only by the quantity needed to fulfill the longer-term, lesser MW request. Powerex argues that no commenter opposed this proposal and that the Commission did not provide any rational basis for its rejection in Order No. 890.

Commission Determination

664. The Commission affirms the decision in Order No. 890 not to eliminate the requirement to match competing requests in order to retain rollover rights. Long-standing policy requires transmission customers, at the time of rollover of their contracts, to match competing requests for service as to term and rate. We disagree with petitioners who claim that the requirement of a five-year minimum contract term, or the terms of FPA section 217, necessitate any change to our matching policy. The same rationale for the matching policy articulated in Order No. 888 and its progeny with regard to the original rollover right applies with equal force to the reformed rollover right. That is, the matching policy provides a mechanism not only for awarding capacity to those who value it most, but also for breaking ties.[261] We do not see how a change to a five-year minimum contract term diminishes the need for, or the efficacy of, such a mechanism.

665. As we noted in Order No. 890, absent the requirement that a customer match the term of a competing request, transmission providers could be forced to enter into shorter-term arrangements that could be detrimental from both an operational standpoint, including system planning, and a financial standpoint.[262] While it is true that the extension of the minimum rollover term from one to five years will otherwise enhance the transmission provider's ability to fulfill its planning and construction obligations, it does not follow that the transmission provider should be required to forgo the operational and financial certainty of an even longer-term competing request at the time of a rollover. By awarding capacity to the customers that value it the most, the matching requirement benefits all longer-term customers, whether LSEs or other classes of customers, and is therefore fully consistent with the requirements of FPA section 217.

666. We reiterate our existing policy that, in the event of competing, mutually exclusive requests for network resource designations, the network customer seeking rollover must match the term of the competing network resource power contract.[263] However, we agree with TAPS that, given the differing nature and obligations of network service versus point-to-point service, a network customer seeking rollover of its network service for a designated resource should be able to match a competing point-to-point request by extending its network service agreement rather than the power contract supporting the network resource designation.[264] We also clarify, in response to Powerex, that a customer exercising a rollover right is only required to match a *bona fide* competing commitment to take service, evidenced for example by a pre-confirmed transmission request or the execution of a contingent service contract. We disagree with Ameren, however, that the transmission provider should be permitted to effectively shorten the customer's notice period by requiring the rollover customer to match a competing request prior to the date by which its rollover notice would otherwise be required.

667. With these clarifications, we continue to believe that it is not unreasonable to require network customers to match competing requests for their capacity, even if made by marketers in order to engage in resales of capacity or by the transmission provider itself. Matching ensures that the customers that value the capacity the most are awarded the capacity. In any event, we believe it unlikely that a network customer would be routinely faced with viable competing requests from a point-to-point customer seeking service at the time of the rollover because of the significant differences between network transmission service (under which loads and resources are designated, but not specific points of

[261] *See* Order No. 888–A at 30,197.

[262] *See* Order No. 890 at P 1255 (citing Order No. 888–A at 30,197).

[263] *See WPPI* 84 FERC at 61,655–56.

[264] Any subsequent request to designate a network resource would remain subject to the requirements of the *pro forma* OATT, as with any other request to designate a network resource.

receipt and delivery) and point-to-point service (under which such points are required to be designated).

668. We disagree with APPA's suggestion that rollover customers should be relieved of having to match competing requests because the transmission provider is planning and upgrading its system on the assumption that the rollover customer will continue service. The matching requirement only arises if there are competing requests, *i.e.*, notwithstanding any upgrades constructed or planned, capacity will not be available to serve both the rollover customer and the competing customer. If there is a *bona fide* request from a competing longer-term customer, it is reasonable to expect the rollover customer to match the request in order to ensure that capacity is awarded to the customer that values it the most.

669. Finally, we further clarify in response to Powerex that, in cases where a rollover customer loses service to a longer-duration competing request for a lesser quantity, the rollover of the original request should only be displaced by the quantity needed to fulfill the longer-term request for a lesser quantity. In such instances, the transmission provider should grant service to the competing customer and reduce the amount of capacity available for roll over by the original customer accordingly.

d. Rollover Restrictions Based on Native and Network Load Growth

Requests for Rehearing and Clarification

670. TDU Systems ask the Commission to eliminate the ability of transmission providers to restrict other LSEs' rollover rights based on forecasts of the transmission provider's retail and wholesale native load growth. TDU Systems argue that extending the minimum term to qualify for rollover rights effectively provides the transmission provider five years of notice that it will need to construct transmission upgrades to serve its native load growth. Thus, TDU Systems contend, there is no justification for that transmission provider to fail to build to meet its service obligation within this period. TDU Systems further contend that permitting a transmission provider to avoid its obligation to build for its known native load growth by curtailing an LSE customer's rollover rights gives an undue preference to the transmission provider's native load and violates the Commission's comparability principle. TDU Systems argue this also violates FPA section 217(b), which it contends does not distinguish between the transmission provider's native load and the native load of other LSEs.

671. If the Commission does not eliminate the ability of the transmission provider to restrict rollover rights based on its own forecasted load growth, TDU Systems ask, at a minimum, that the Commission require transmission providers to treat the load growth of other LSEs with native load service obligations in the same manner as the transmission provider's own native load growth. NRECA makes a similar request, arguing that comparability requirements and FPA section 217 should place the service obligations of all LSEs on an equal footing. NRECA asks the Commission to confirm that a transmission customer using rollover rights to serve native load enjoys the same priority as a transmission provider serving its own retail native load and will be factored into any native load growth forecasts.

672. By contrast, South Carolina E&G and South Carolina Regulatory Staff argue that the Commission should expand the ability of transmission providers to restrict rollover rights. South Carolina Regulatory Staff asks the Commission to ensure that native load growth is not marginalized by new non-native customers. The South Carolina Regulatory Staff expresses concern that native load service may be forced to yield to other service if the transmission provider's native load forecasts turn out to be wrong. South Carolina E&G agrees, arguing that limiting the ability of transmission providers to restrict rollover rights only in the initial service agreement puts service to native load at an unreasonable risk. South Carolina E&G requests that transmission providers be allowed to add rollover restrictions at the time of each rollover (rather than only at the initiation of service) to reflect changes in load growth forecasts.

673. Alternatively, South Carolina E&G suggests that the Commission provide for a procedure that would allow the transmission provider to terminate rollover rights when new facility construction is required during system planning, *i.e.*, at any point the transmission provider determines that a new facility is necessary to accommodate a new request or projected native load growth, given the possibility of full rollover by eligible customers. South Carolina E&G proposes that transmission providers be required to promptly give notice of that determination, which would trigger a limited period of time (*e.g.*, 30 days) for each long-term customer to indicate whether it desires to rollover its current contract for another designated period of time. Absent such election by the customer within the designated time, South Carolina E&G proposes that the customer's rollover rights be terminated. South Carolina E&G argues that this proposal would provide at least partial protection against the inequitable prospect of being forced to construct facilities that would be needed in the event of full rollover of service, only to be left ''high and dry'' by a customer's failure to exercise its rollover rights. South Carolina E&G argues its alternative proposal would ensure that native load does not subsidize the customer seeking rollover.

674. If the Commission declines to modify its rollover policies, South Carolina E&G suggests the adoption of a native load curtailment priority to ensure that continued service to the rollover candidate does not impinge on native load service. Specifically, South Carolina E&G states that point-to-point customers could receive rollover rights, but if curtailment is required, then that rollover contract (like all other point-to-point contracts) would be curtailed before native load. South Carolina E&G also asks the Commission to provide greater specificity regarding the meaning of the statement in Order No. 890 that, in forecasting native load growth, consideration should be given to state-approved integrated resource plans that show a native load need for the capacity. South Carolina E&G asks the Commission to specify whether such a plan would be a determining factor in the Commission's evaluation of a transmission provider's native load growth forecast, how much weight the Commission would place on the existence of such a plan, and whether the plan would need to incorporate specific elements.

Commission Determination

675. The Commission continues to believe it is appropriate to require that rollover restrictions be based on reasonable forecasts of native load growth or preexisting contracts that commence in the future and that such restrictions be included in the initial transmission service agreement. As explained in Order No. 890, this will remain the only appropriate way to restrict a rollover right.[265] We are not persuaded by petitioners' arguments that the requirement of a five-year minimum contract term, or the native load protections found in FPA section 217, necessitates any change to this policy. The same rationale for this policy articulated in Order No. 888 and its progeny with regard to the original

[265] *See* Order No. 890 at P 1256.

rollover right applies with equal force to the reformed rollover right.[266]

676. We disagree with TDU Systems that extending the minimum term to five years justifies eliminating the ability of the transmission provider to restrict a customer's rollover right. The transmission provider is allowed to restrict a rollover right in favor of its reasonably forecasted native load growth in order to ensure that capacity that exists on the provider's system, at the time of entering into a contract with a customer seeking a rollover right, can be recalled for the use of its reasonably forecasted native load growth at some time in the future. Our longstanding policy, which was not changed by Order No. 890, permits transmission providers to reserve *existing* capacity for the use of its reasonably forecasted native load growth.

677. Arguments that the transmission provider has more time to plan for upgrades to meet its native load growth because of the new five-year minimum contract term miss the point. A transmission provider should not be forced to allow rollover where, at the time of entering into a five-year transmission contract with a customer for existing capacity, it can show that it will need to reclaim that capacity to serve its reasonably forecasted native load growth. Customers that are denied rollover rights may nonetheless secure transmission service by submitting service requests for the period in question and committing to fund any necessary upgrades.

678. Alternatively, TDU Systems and NRECA ask the Commission to require transmission providers to treat the load growth of other LSEs with native load service obligations in the same manner as the transmission provider's own native load growth during forecasting. This is already our policy. In Order No. 888-B, the Commission, in addressing a transmission provider's ability to recall capacity needed for native load growth, clarified that ''network transmission customers are afforded the same treatment as the transmission provider on behalf of native load (retail and wholesale requirements customers) in terms of the reservation of existing transmission capacity by the transmission provider.'' [267] This ensures that the LSE's native load is treated the same as the transmission provider's native load at the time a rollover restriction is considered.

679. We reject the argument of South Carolina E&G and South Carolina Regulatory Staff that the Commission should expand the ability of transmission providers to restrict rollover rights by, for example, allowing rollover restrictions to be added at the time of each rollover (rather than only at the initiation of service) or when the need for new facilities arises. We continue to believe that requiring transmission providers to determine at the initiation of service whether they have a reasonably forecasted native load growth need for the capacity strikes a reasonable balance between the transmission provider's needs and those of its customers seeking long-term transmission service with a rollover right.[268] If we were to allow the transmission provider the ability to seek to restrict a rollover at the time of each rollover, as suggested by South Carolina E&G, it would vitiate the benefit of the rollover right to transmission customers, many of which also have load-serving obligations. We note, however, that South Carolina E&G's concerns should be mitigated going forward since our requirement of a five-year minimum contract term, as well as the one-year notice period and the other rollover reforms, will ensure greater consistency between the rights and obligations of customers and the planning and construction obligations of transmission providers.

680. We also decline to adopt South Carolina E&G's suggestion that point-to-point customers with rollover rights be curtailed before native load. The Commission has long required that firm point-to-point customers share the same curtailment priority as network customers and the transmission provider serving native load except in the limited circumstance when it would require the shedding of bundled retail load.[269] Nothing in our changes to rollover policies justifies modifying that requirement. We also decline to determine generically the weight to be given to state-approved integrated resource plans in the determination of reasonable native load restrictions. The determinative factors in each case will be identified based on the record, along with the relevant particular supporting documentation to be considered.

e. Effectiveness Upon Acceptance of Coordinated and Regional Planning Process

Requests for Rehearing and Clarification

681. Duke argues that the rollover reforms should be implemented immediately and not upon acceptance of the transmission provider's planning process compliance filing. Duke contends that the Commission unambiguously found that the prior rollover policy was no longer just and reasonable and not unduly discriminatory. Duke also argues that the prior rollover policy is inconsistent with FPA section 217, suggesting that the prior policy conflicts with the reasonable needs of LSEs to satisfy their service obligations. Duke therefore argues that it is not reasonable for the Commission to allow its prior rollover policies to remain in place pending acceptance of the transmission planning process compliance filings. Duke contends that the Commission did not base its finding that rollover policies were in need of reform on the lack of transmission planning processes and, therefore, making one conditioned on the other is unsupported.

682. TAPS requests clarification of the timing of compliance filings implementing the new rollover policies. TAPS questions whether transmission providers were required to submit conforming changes to section 2.2 in their initial compliance filings or as part of the Attachment K compliance filings due at a later date. If the former, TAPS states that transmission providers would be deleting the current language that will still be in effect. TAPS suggests that changes to section 2.2 not be made until the Attachment K is accepted.

Commission Determination

683. The Commission denies rehearing of the determination to tie the effectiveness of rollover reform to the acceptance of the transmission provider's coordinated and regional planning process required under Order No. 890. As the Commission explained in Order No. 890, reforms regarding rollovers and transmission planning must proceed together because they are closely related. Under our longstanding policy, transmission service eligible for a rollover right must be set aside for rollover customers and included in transmission planning. Duke is therefore incorrect in suggesting that the Commission did not rely on our planning-related reforms when fashioning a remedy to ensure rollover

[266] *See* Order No. 888 at 31,694; Order No. 888–A at 30,198.

[267] *See* Order No. 888–B at 62,084–85.

[268] In addition, we believe that putting the onus on the transmission provider to determine the limitations of its system and its own native load growth needs at the time of the initial service agreement appropriately allocates responsibility and encourages accuracy. Allowing transmission providers the ability to reevaluate their native load growth needs on an ongoing basis, or to escape obligations to serve rollover customers when upgrades are identified, would tend to discourage a thorough review upfront.

[269] *See Northern States Power Co.*, 89 FERC ¶ 61,178 (1999).

policies remain just and reasonable and not unduly discriminatory.

684. With regard to TAPS' concern regarding the timing of compliance filings implementing the new rollover policies, we reiterate that the previously existing rollover provisions will remain in effect for the transmission provider until such time as the Commission accepts the transmission provider's Attachment K compliance filing. Accordingly, it is only after a transmission provider's Attachment K planning process is accepted by the Commission that the transmission provider should file the rollover reform language, and the effective date of that language should be commensurate with the date of that filing. We have revised section 2.2 of the *pro forma* OATT to make this clear.

f. Transition Issues

Requests for Rehearing and Clarification

685. Great Northern seeks clarification, or in the alternative rehearing, regarding how rollover reform would apply to transmission service requests that were made before the issuance of Order No. 890 in reliance on the prior version of section 2.2 of the *pro forma* OATT. If Order No. 890 is implemented in such a way as to require a minimum five-year contract term in order for rollover rights to attach to pending transmission service requests, Great Northern contends it would cause significant disruption in the development and financing of competitive generation projects already in the queue. Great Northern suggests that requiring pending projects to submit new contracts for five-year terms in order to obtain rollover rights in turn would require it to restart its project planning process for each of those projects.

686. Great Northern therefore asks the Commission to confirm that the current one-year contract commitment right of first refusal rule will continue to apply to transmission service requests that were made prior to the issuance of Order No. 890 and that the five-year contract commitment right of first refusal rule will not apply until the first rollover date after both the executed transmission service contract and revised section 2.2 of the transmission provider's *pro forma* OATT have become effective. If the Commission is not inclined to make such a generalized determination in this proceeding, Great Northern requests the Commission to rule that, in the specific circumstances where a customer has requested transmission service for one year with rollover rights as described in section 2.2 of the OATT, and thus the transmission provider was on notice of the potential need to exercise rollover rights, it will allow rollover rights to apply until the first rollover date after both the executed transmission service contract and revised section 2.2 of the transmission provider's OATT have become effective.

687. NCEMC, NRECA, and TDU Systems request that the Commission clarify that a transmission customer will be permitted to rollover an existing contract one time at the current terms and conditions following the effective date of Order No. 890, as this would avoid any impairment of the contracts entered into by parties prior to the Commission's change in rollover rights policy, consistent with *Mobile-Sierra* requirements.[270] By granting one rollover with the same terms and conditions following the effective date of Order No. 890, these petitioners assert that the Commission will permit the parties to fulfill all obligations under their previously-negotiated transmission contracts and then, following this rollover, enter into new transmission and power supply contracts with full knowledge of the Commission's new rollover policy. They contend that certain preamble language could be understood to permit a customer to rollover a contract one time at the currently-effective terms and conditions following the effectiveness of the rollover reforms,[271] whereas reformed section 2.2 suggests that the five-year term requirement and notice provision will become effective on the first rollover following effectiveness of the rollover reforms.[272]

688. TAPS contends that there could be confusion stemming from the language in the Order No. 890 version of section 2.2, which states that the ''five-year/one-year requirement'' will apply ''on the first rollover date'' after Attachment K is accepted. TAPS believes this language could be read to require that a customer's first rollover after the effective date of Attachment K must be exercised one year prior to the end of the existing service agreement, which is at odds with the Commission's recognition that some contracts may not have a year left on them and therefore the 60-day notice should apply to such contracts.[273] TAPS suggests specific amendments to section 2.2 of the *pro forma* OATT to more clearly state the process for rolling over service during the transition period.

689. Powerex also asks that section 2.2 be amended to more clearly state the Commission's rollover policies, arguing that discriminatory and anticompetitive practices are more likely to occur in areas where the transmission provider retains discretion. Powerex suggests that the Commission clarify that customers with existing long-term contracts with rollover rights must only provide 60-days prior notice of their desire to roll over their capacity and that the rollover may be for a one-year term with no rollover rights or a five-year term with rollover rights. TransServ, however, argues that the modified notice requirements of section 2.2 should apply only to existing long-term agreements set to expire within one or two years of the effective date of the new five-year/one-year long-term service requirements. TranServ argues that allowing existing customers with longer-term contracts to retain a 60-day notice provision for many years into the future would unnecessarily complicate and delay the transmission provider's ultimate conversion of all existing service agreements to comply with the new five-year/one-year provisions for long-term firm service.

690. Ameren and Tenaska ask the Commission to clarify that notice of a rollover given prior to the effectiveness of rollover reform would remain subject to the pre-Order No. 890 rollover polices, including the existing customer's willingness to accept a term of one year (or the term offered by a competing applicant, if longer).

Commission Determination

691. We agree with Great Northern that requiring a five-year minimum contract term in order for rollover rights to attach to pending transmission service requests could cause significant disruption to those transmission customers already in the transmission queue at the time of the effective date of Order No. 890. These customers requested service believing that they only needed to enter into a one-year contract in order to obtain a rollover right. Accordingly, we grant rehearing and revise section 2.2 of the *pro forma* OATT to provide that the current one-

[270] *Citing United Gas Pipe Line Co.* v. *Mobile Gas Services Corp.*, 350 U.S. 332 (1956); *Federal Power Commission* v. *Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

[271] *Citing* Order No. 890 at P 1238 (''existing transmission contracts will be permitted to roll over under their existing terms until the first such rollover opportunity following the effectiveness of the reforms required by this Final Rule.'').

[272] *Citing* reformed section 2.2 (''[s]ervice agreements subject to a right of first refusal entered into prior to [the acceptance by the Commission of the Transmission Provider's Attachment K], unless terminated, will become subject to the five-year/one-year requirement on the first rollover date after [the acceptance by the Commission of the Transmission Provider's Attachment K].'').

[273] *Citing* Order No. 890 at P 1267.

year contract commitment requirement will continue to apply to all transmission service requests that were in a transmission provider's transmission queue as of the effective date of the reforms adopted in Order No. 890 (*i.e.*, July 13, 2007). For such transmission requests, the five-year contract commitment requirement will not apply until the first rollover date after both the execution of the transmission service contract and effectiveness of the revised section 2.2 for the particular transmission provider.

692. We disagree with other petitioners, however, that a transmission customer should be permitted to roll over any other existing contracts one time at the current terms and conditions following the effective date of the rollover reforms. As we explained in Order No. 890, ''[i]t is only a rollover contract entered into or renewed after the effectiveness of rollover reform that must comply with the new rollover provisions.'' [274] While it is true that the customer rolling over service after the effectiveness of the reforms will be required to agree to a minimum five-year term to obtain rollover rights for the new agreement, this does not impair the customer's rights or obligations under its existing contract.

693. To the extent there is any confusion regarding the discussion in Order No. 890 of when the rollover reforms apply to existing customers, we clarify that an existing customer must comply with the new rollover reforms at the time of the first rollover of its contract occurring after the effectiveness of the rollover reforms for its transmission provider, as provided in the revisions to section 2.2 of the *pro forma* OATT. For example, if an existing customer's contract expires January 1, 2009, and rollover reform became effective on January 1, 2008 for its transmission provider, then any contract entered into by the customer at the time of expiration of its existing contract on January 1, 2009 would have to comply with the rollover reforms (*e.g.*, the new contract must be for a minimum term of five years to retain a rollover right and, if so, one-year notice must be given to exercise that right at the expiration of the contract).

694. In response to TAPS and Powerex, we reiterate that a transmission customer with an existing contract that seeks to exercise its rollover after the effectiveness of rollover reform may exercise this rollover based on the existing 60-day notice rule, in recognition of the fact that during this transition period certain customers may not have a year or more left on their existing contracts.[275] We agree, however, with TranServ that allowing existing customers with longer-term contracts to retain a 60-day notice period provision for many years in the future would unnecessarily complicate and delay the transition to rollover reform. Allowing existing customers to utilize the 60-day notice rule was intended largely to address the situation where a given customer does not have a year or more left on its contract such that it is possible to give one-year notice. This, of course, is not the case with existing contracts that have many years left in their terms before expiration.

695. We therefore clarify that the current 60-day notice rule will continue to apply only to those existing contracts that have less than five years left in their terms at the time of effectiveness of rollover reform for its transmission provider. Any customer with an existing contract with five or more years left in its term at the time of effectiveness of rollover reform for its transmission provider will be required to give one-year notice of whether it intends to exercise its rollover right. We emphasize that, whether an existing transmission customer is required to give 60-days or one-year notice when exercising its rollover right under its existing contract, the customer must enter into a minimum of five years of service and meet any of the other requirements of the reformed rollover right in order to retain a rollover right going forward. An existing customer may rollover its service for a term of less than five years, but will not then retain a rollover right for this service. We revise section 2.2 of the *pro forma* OATT to make these requirements clear.

696. In response to Ameren and Tenaska, we reiterate that notice of a rollover given prior to the effectiveness of rollover reform remains subject to the pre-Order No. 890 rollover policies, including the existing customer's willingness to accept a term of one year (or the term offered by a competing applicant, if longer).[276]

3. Modification of Receipt or Delivery Points

697. Pursuant to Section 22 of the *pro forma* OATT, a transmission customer taking firm point-to-point service may modify its receipt and delivery points, *i.e.*, redirect its service, on either a non-firm or firm basis. In Order No. 676, the Commission adopted the ''Standards for Business Practices and Communication Protocols for Public Utilities'' developed by the NAESB's Wholesale Electric Quadrant (WEQ).[277] The WEQ standards include standards addressing requirements for redirects on both a firm and non-firm basis, all of which were incorporated by reference into the Commission's regulations except for WEQ Standard 001–9.7, which addressed the impact of redirects on the rollover rights of a long-term transmission customer. Order No. 676 directed the WEQ to reconsider WEQ Standard 001–9.7 and develop a revised standard consistent with Commission policy.

698. In Order No. 890, the Commission affirmed reliance on the NAESB process to develop business practices implementing the Commission's redirect policy. The Commission also determined that the reforms adopted in Order No. 676, in combination with the OATT-related reforms adopted in this proceeding, were adequate to ensure that transmission providers do not engage in undue discrimination when a customer seeks to modify its receipt and delivery points on a firm basis. With respect to the effect of redirects on rollover rights, the Commission affirmed its policy allowing a redirect of firm, long-term service to retain rollover rights, even if the redirect is requested for a shorter period. The Commission concluded that a transmission customer should not have to choose between maintaining its rollover rights and redirecting on a firm basis. The Commission noted, however, that any change to a delivery point would be treated as a new request for service for purposes of determining availability of capacity. As a result, a redirect right does not grant the customer access to system capacity or queue position different from other customers submitting new requests for service. The Commission also provided guidance regarding the processing of, and pricing for, redirected service.

Requests for Rehearing and Clarification

699. MISO seeks rehearing of the Commission's decision to allow rollover rights to follow the redirected service, asking that rollover rights be limited or eliminated altogether in the event of a

[274] *See id.*

[275] *See id.*

[276] *See id.* at P 1238 (''existing transmission contracts will be permitted to roll over under their existing terms until the first such rollover opportunity following the effectiveness of the reforms required by this Final Rule.'').

[277] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676, 71 FR 26199 (May 4, 2006), FERC Stats. & Regs. ¶ 31,216 (2006), *reh'g denied*, Order No. 676–A, 116 FERC ¶ 61,255 (2006), *order on reh'g*, Order No. 676–B, 72 FR 21095 (Apr. 30, 2007), FERC Stats. & Regs. ¶ 31,246 (2007).

redirect. MISO argues that the Commission's statement that it was simply continuing its existing rollover policy is confusing since the Commission found that the current rollover policy was no longer just and reasonable. MISO also contends that the precedent cited by the Commission does not support migration of rollover rights to a redirected path. Even if the rollover policy were justified under the Commission's precedent, MISO argues that the Commission's finding that the policy is no longer just and reasonable undermines continued reliance on that precedent.

700. If the Commission decides to maintain rollover rights for redirects, MISO proposes the following limitations and requests the Commission to direct NAESB to draft its business practices accordingly. First, MISO suggests that the primary path agreement should have a term of at least five years for any rollover rights to attach. Second, MISO requests that any redirect must be for firm service for one year or longer. If the redirect is for a shorter period, MISO contends that the rollover rights should remain with the original path. Third, MISO requests redirected service to terminate on the same date as the parent service so as to maintain the timing for execution of rollover rights. Finally, MISO suggests that in order to execute a rollover right the redirected service must be requested and granted prior to the one-year deadline for the customer to request rollovers along the original path.

701. Bonneville requests a similar clarification of the application of rollover rights to redirects. Bonneville argues that a literal reading of the revised *pro forma* OATT allows a long-term point-to-point customer to request redirected service within the last year of its service contract, maintain its rollover rights, and apply them to the new points even though it is unable to give a year's notice of intent to rollover at those points. Bonneville therefore seeks clarification from the Commission that rollover rights will remain with the original points unless the customer redirects service for at least one year. Without clarification, Bonneville contends that redirecting customers will have greater rights than customers that do not redirect, who must give one-year's notice.

702. TranServ also requests clarification regarding the requirement for the rollover right to follow the redirect, regardless of the duration of the redirect. TranServ questions whether a redirect of a long-term firm service reservation for one day qualifies that customer for rollover rights on the redirected service points. TranServ suggests that the Commission instead restrict rollover rights on redirected service points to redirects of five years or longer and further require that the redirect be co-terminus with the original request being redirected. TranServ argues that more guidance regarding implementation of the rollover and redirect policies will facilitate the NAESB standards development process.

703. MidAmerican requests clarification regarding the queuing of service requests as applied to redirects. MidAmerican argues that a request to redirect service should not result in a release of transfer capability for third-party service requests in the queue, since the increase in transfer capability is contingent upon the approval of the redirect request. MidAmerican argues that this approach is consistent with the requirement in section 17 of the *pro forma* OATT to use the ''same system assumptions and analysis applicable to any other new request for service, including whether sufficient ATC exists,'' when analyzing the ability to grant a request for redirected service.

Commission Determination

704. The Commission denies petitioners' requests to amend the rights of rollover customers to redirect their service. Under section 22.2 of the *pro forma* OATT, a request for a firm redirect must be treated like a request for new transmission service.[278] As a new request for service, each redirect request is subject to the availability of capacity and subject to the possibility that the transmission provider may not be able to provide rollover rights on the new redirected path. The transmission provider is required to offer rollover rights to a customer requesting a firm redirect only if rollover rights are available on the redirected path, *i.e.*, to the extent not restricted based on reasonable forecasts of native load growth or preexisting contracts that commence in the future.[279]

705. As the Commission explained in Order No. 890, rollover rights follow the redirect regardless of the duration of the redirect.[280] A transmission customer making a firm redirect request does not convert its original long-term firm transmission service agreement into two short-term service agreements, nor does it lose its rollover rights under its long-term firm transmission service agreement.[281] At the same time, a customer can exercise its rollover right only at the end of the contract. Thus, if a customer with rollover rights chooses to redirect its capacity for less than the full remaining term of the contract, absent some further request to redirect, the original path will automatically be reinstated and rollover rights would remain on only the original path. By contrast, if the customer chooses to redirect its capacity until the end of its contract, the customer would have rollover rights along only the redirected path, and only to the extent not restricted based on native load growth or future contracts along the redirected path.

706. We therefore reject requests to restrict rollover rights to longer-term redirects. A long-term transmission customer may request multiple, successive redirects for firm service. This discretion is limited by the fact that each successive request is treated as a new request for service in accordance with section 17 of the *pro forma* OATT. Each request is therefore subject to the availability of capacity and subject to the possibility that the transmission provider may not be able to provide rollover rights on the new, redirected path.[282] If the customer has not been granted rollover rights for a redirect that extends to the end of its contract, the redirected service will terminate on the same date as the parent service.

707. We also reiterate that a customer cannot exercise any rollover rights unless it first has provided the appropriate notice to the transmission provider. If a customer requests and is granted a rollover right prior to the relevant notice deadline (60 days for pre-Order No. 890 agreements or one year for all others) and subsequently requests and is granted a redirect for firm service for the remainder of the contract term (*i.e.*, within the notice period), the new reservation governs the rights at the new receipt and delivery

[278] *See* Order No. 890 at P 1268.

[279] *See* Order No. 676 at P 51.

[280] Order No. 890 at P 1280.

[281] *Id.*; *see also Commonwealth Edison Co.*, 95 FERC ¶ 61,027 at 61,083 (2001) (explaining that a request to change delivery points on a firm basis for one month, followed by a reversion to the original points does not convert the existing long-term firm agreement into two separate short-term agreements); *American Electric Power Service Corp.*, 97 FERC ¶ 61,207 at 61,905–06 (2001).

[282] For example, assume a transmission customer with a five-year agreement for firm service between points A and B, who qualifies for rollover rights on that path. If the transmission customer seeks to redirect on a firm basis in year 3 to points C to D and then redirect back to points A and B thereafter, at the end of the five year agreement the transmission customer would have rollover rights only with respect to points A to B. If, however, the transmission customer seeks to redirect to points C and D for the last six months of the contract term and both qualifies for rollover rights on this path and has requested rollover within the notice period of the contract, the customer would then have rollover rights only with respect to points C and D. *See* Order No. 676 at P 59.

points and the customer can obtain rollover rights with respect to the redirected capacity to the extent rollover rights are available for the redirected points. If, however, a customer fails to request a rollover right prior to the relevant notice deadline, the customer forfeits rollover rights along the current or any redirected path.

708. We clarify, to the extent necessary, that transfer capability is not freed up for earlier queued service requests until a redirect has been granted. A redirect request must be evaluated in accordance with section 17 of the *pro forma* OATT using the same system assumptions and analysis applicable to any other new request for service, including whether sufficient ATC exists to accommodate the request.[283] If there is insufficient ATC to offer service to customers in the queue, and an existing customer requests redirected service, any increase in ATC along the original path is contingent upon the acceptance and confirmation of the redirect. It cannot be assumed at the time of a redirect request that the transmission provider will grant the request.

4. Acquisition of Transmission Service

a. Processing of Service Requests

(1) Posting Performance Metrics

709. To enhance the transparency of the study process and shed light on whether transmission providers are processing studies in a timely and non-discriminatory manner, Order No. 890 required all transmission providers, including RTOs and ISOs, to post on their OASIS sites certain metrics that track their performance in processing system impact studies and facilities studies associated with requests for transmission service. Specifically, the Commission required all transmission providers to post on a quarterly basis performance metrics associated with: processing time from initial service requests to the offer of a system impact study; system impact study processing time; service requests withdrawn from the system impact study queue; processing delays for system impact studies caused by transmission customer actions; processing time from completed system impact study to the offer of a facilities study; facilities study processing time; service requests withdrawn from the facilities study queue; and, processing delays for facilities studies caused by transmission customer actions. The Commission required transmission providers to begin tracking these performance metrics upon the effective date of Order No. 890 and keep the quarterly performance metrics posted on their OASIS sites for three calendar years.

710. The Commission also required transmission providers, including RTOs and ISOs, to submit a notification filing to the Commission in the event the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT for two consecutive quarters. The transmission provider may explain in its notification filing that it believes there are extenuating circumstances that prevented it from meeting the deadlines in the *pro forma* OATT. Absent a determination from the Commission that delays were due to extenuating circumstances, the transmission provider is required to post additional metrics regarding the average number of hours expended on, and the number of employees dedicated to, system impact studies and facilities studies. Unless otherwise directed by the Commission, the transmission provider must begin posting the additional performance metrics the quarter following the notification filing.

711. The Commission delegated to NAESB the responsibility for developing the Standard and Communications Protocols, business practices and OASIS modifications that will be necessary to implement the performance metrics.

Requests for Rehearing and Clarification

712. Two transmission providers object to aspects of the standard performance metric posting requirements. Ameren objects to the requirement that RTOs post these metrics, arguing that the requirement may increase an RTO's cost even though it is unnecessary for the efficient operation of competitive markets. Ameren argues that RTOs are by definition independent entities that lack the incentive to favor any transmission customer over another and, therefore, the performance metrics will serve no purpose in uncovering potential discrimination in the study request process. Ameren argues that information already posted by MISO and other RTOs allows the Commission to obtain the data it seeks without placing additional requirements on RTOs.

713. Old Dominion argues that the Commission should include in the standard performance metrics any denials or delays in the construction phase of transmission service requests, suggesting that review of whether requested transmission service is effected through construction of identified upgrades and other facilities is a logical and necessary outgrowth of Order No. 890.[284] Old Dominion asks the Commission to require transmission providers to add to the standard performance metrics: the time period of any such postponement or delay; the MW amount of congestion caused by the delay, if any; the amount of transmission rights underfunding caused by the delay, if any; and, whether the delay resulted in any degradation of system reliability. Old Dominion contends that the progress of each project is essential for transmission providers to determine whether transmission service requests can be accommodated and whether a transmission project is actually constructed or not has an effect on the study process for subsequent projects in the queue.

714. Other transmission providers object to the aspects of the additional performance metrics triggered by consistently processing studies outside the 60-day due diligence deadline. Washington IOUs ask that the Commission require transmission providers to post information on employees and employee-hours devoted to study processing only if the Commission first determines that delays in processing study requests are not excused by extenuating circumstances. Washington IOUs contend that the Commission's requirement, in Order No. 890, to calculate and post this additional information will create a significant additional burden and fails to recognize that the 60-day window is a target, not a deadline. They further contend that customers may ask that additional time be taken in the processing of studies. Absent a determination that delays in processing study requests are a result of a lack of good faith and due diligence on the part of the transmission provider, Washington IOUs argue that there should be no requirement to track and post employees and employee-hours devoted to study processing.

715. Washington IOUs also ask that the Commission not count transmission requests submitted as part of a transmission provider's Integrated Resource Planning (IRP) process in the calculation of percentages of studies performed outside the 60-day window. They contend that transmission requests associated with such studies are often made years in advance to ensure that transmission for service of long-term

[283] Order No. 890 at P 1285.

[284] Old Dominion also argues that the Commission should require performance reports regarding transmission planning activities, which the Commission addresses in section III.B.

load is available and can be discussed in the public domain, to allow operational personnel to confer with one another on IRP issues in a public forum while adhering to the Commission's standards of conduct, and to ensure that the utility will be able to reserve transmission capacity necessary to serve the utility's native load reliably and in a cost-effective manner. Washington IOUs argue that there is no need for studies associated with these requests to be performed within the 60-day window.

716. Southern argues that the Commission should grant rehearing so that studies for which the customer has requested or expressly agreed to extend the 60-day study period should not be required to be included among those studies considered to be completed late. Southern contends that it would be arbitrary and capricious to include studies that are ''late'' due to no fault of the transmission provider (e.g., studies delayed or extended due to customer request or action) in the metrics calculations. Southern states that doing so could cause the transmission provider to be automatically penalized with additional reporting requirements and cross the threshold for which the transmission provider must proffer excuses acceptable to the Commission or suffer significant penalties.

Commission Determination

717. The Commission denies rehearing of the decision in Order No. 890 to require transmission providers to post standard performance metrics regarding the processing of system impact studies and facilities studies and, for consistently late studies, additional performance metrics regarding the resources dedicated to processing studies. These posting requirements are necessary to promote greater market transparency and establish important incentives for all transmission providers to complete transmission service requests in a timely and transparent fashion. As the Commission explained in Order No. 890, despite the fact that some transmission providers currently post some information related to the processing of transmission service requests on their OASIS, much of the public information currently posted by transmission providers lacks transparency, accessibility, and consistency.[285]

718. We affirm the decision to subject all transmission providers, including RTOs and ISOs, to the same reporting requirements. While it may be true that data already posted by RTOs and ISOs provides much of the information contained in the standard performance metrics, it does not follow that posting the remaining information is unnecessary. The independent nature of RTOs and ISOs does not justify relieving them of this particular obligation. All transmission providers should be subject to the same posting requirements to enhance uniformity and transparency in processing transmission service requests and transmission studies. Indeed, to the extent an RTO or ISO is already posting much of this information, the incremental burden of posting the remaining information should be minimal.

719. The Commission does not believe it is appropriate at this time to add posting requirements regarding denials or delays in the construction phase, as requested by Old Dominion. While construction delays can affect transmission service start dates, the transmission provider will be in communication with the relevant customers regarding the status of those projects. The transmission provider is also required to make available information regarding the status of upgrades identified in its transmission plan, as we discuss in section III.B. We are not persuaded that, based on the evidence before us at this time, additional posting requirements for denials or delays in the construction phase of transmission service requests are necessary or appropriate. Absent particular evidence to the contrary, we believe that other OATT provisions such as section 21.2 and the current standard performance metrics adequately protect customers from inappropriate delays or discrimination during construction phases.

720. We also affirm the decision to require any transmission provider that processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT for two consecutive quarters to submit a notification filing to the Commission and post additional performance metrics. We disagree with Washington IOUs that transmission providers should be required to post these metrics only after Commission action on a notification filing. Posting of these additional metrics is not required until two months after the notification filing, giving the Commission time to consider the extenuating circumstances that prevented the transmission provider from processing requested studies on a timely basis. If, upon review of such a filing, the Commission finds that delays were caused by extenuating circumstances, the Commission will not require the transmission provider to continue to post the additional performance metrics. As a result, we expect transmission providers with legitimate extenuating circumstances should not have to post any additional metrics.

721. Similarly, we decline to exempt, as a general matter, studies that are delayed by customer agreement or that are associated with resource planning. The transmission provider can explain the circumstances surrounding any particular delay in its notification filing, which the Commission will review on a case-by-case basis. The process adopted in Order No. 890 is sufficiently flexible to relieve any transmission provider who completes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines for two consecutive quarters from any additional posting requirements, or operational penalties, if the Commission finds the delays were due to extenuating circumstances.

722. The Commission grants rehearing to make several typographical revisions to our rules implementing these posting requirements. In Order No. 890, the Commission stated that short-term and long-term requests for point-to-point service must be aggregated for purposes of the posting requirement in order to ease the burden on transmission providers and in recognition that many customers requesting short-term point-to-point service are unwilling to pay for studies.[286] The accompanying regulations, however, stated that transmission providers must separately calculate and post metrics for long-term and short-term requests.[287] Upon further consideration, we believe it appropriate to allow, but not require, transmission providers to aggregate requests for long-term and short-term point-to-point service for purposes of the posting requirements. We also clarify that the posting requirements apply to all requests for service, including requests for point-to-point service and requests to designate new network resources or loads. We have revised our regulations to make these requirements more clear.

(2) Operational Penalties for Late Studies

723. The Commission determined in Order No. 890 that all transmission providers, including RTOs and ISOs, would be subject to operational penalties when they routinely fail to meet the 60-day due diligence deadlines prescribed in sections 19.3, 19.4, 32.3 and 32.4 of the OATT. Absent

[285] *See* Order No. 890 at P 1308.

[286] *See id.* at P 1309.

[287] 18 CFR 37.6(h)(1).

extenuating circumstances, penalties will apply to any transmission provider that continues to be out of compliance with these deadlines for each of the two consecutive quarters following a notification filing, described above, stating that the transmission provider has not completed request studies on a timely basis. A transmission provider will be deemed out of compliance if it completes 10 percent or more of non-affiliates' system impact studies outside of the deadlines prescribed in the *pro forma* OATT.

724. Operational penalties will be assessed on a quarterly basis, starting with the quarter following the notification filing and continuing until the transmission provider completes at least 90 percent of all studies within 60 days after the study agreement has been executed. The penalty will be equal to $500 for each day the transmission provider takes to complete any system impact study or facilities study beyond 60 days. For any system impact study or facilities study that is still pending at the end of the quarter and that has been in the study queue for more than 60 days, the penalty will equal $500 for each day the study has been in the study queue beyond 60 days.

725. As explained above, the Commission reiterated that transmission providers may document and describe in their notification filing any unique complexities that particular requests introduce into the study process and that prevent the transmission provider from completing a study within the 60-day due diligence timeframe. On review of a notification filing, the Commission will waive operational penalties if a transmission provider establishes that its non-compliance is the result of extenuating circumstances, including factors or events that are truly beyond its control, such as delays caused by the transmission customer. The submission of a notification filing documenting extenuating circumstances will not, however, suspend the obligation of a transmission provider to process at least 90 percent of the study requests within the deadlines, until such time as the Commission issues a final determination on the notification of extenuating circumstances.

726. The Commission declined to alter the 60-day study completion timeframe embodied in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. The Commission concluded that this timeframe adequately balances the need for expeditious resolution of study requests and the need to ensure that the transmission provider can reliably accommodate the transmission service reserved. The Commission also found that the penalty regime adopted in Order No. 890 protects the transmission provider in the event studies take longer to complete due to the new planning requirements or the new requirement to consider conditional firm options.

727. The Commission determined that revenues associated with operational penalties for late studies should be distributed to non-affiliated transmission customers. Transmission providers were directed to propose a method to determine how unaffiliated transmission customers will receive operational penalty distributions. In the event the transmission provider has raised extenuating circumstances in its notification filing, the Commission stated that the transmission provider should not distribute its operational penalty while the Commission is considering the notification filing.

Requests for Rehearing and Clarification

728. NorthWestern challenges the application of any operational penalties for late processing of studies associated with transmission service requests. NorthWestern contends that the most important goal of a system impact study or facility study should be the ability to perform an accurate study, not one that is quick, and that the Commission cites no record evidence that penalties are necessary to prevent unduly discriminatory completion of studies. NorthWestern argues that all transmission providers have a financial incentive to complete system impact studies quickly in order to maximize use of their transmission systems. In NorthWestern's view, it is unreasonable for the Commission to maintain a 60-day period for processing facility studies for transmission service requests, yet allow a 90-day and 180-day timeframe for generator interconnection facility studies which may be equally complicated. NorthWestern argues that a study may take longer than 60 days for a myriad of reasons and, therefore, section 19.9 of the *pro forma* OATT should be eliminated.

729. To the extent the Commission declines to eliminate section 19.9, NorthWestern argues that it should be waived for transmission providers that do not have an affiliate that could benefit from any delay. NorthWestern states that it is a transmission and distribution utility within its Montana service territory without an active power marketing affiliate and, as a result, the Commission's rationale for imposing penalties is not applicable to NorthWestern and similarly-situated transmission providers.

730. Several petitioners ask the Commission to clarify that penalties will be assessed only if the transmission provider fails to exercise due diligence in completing studies within 60 days. EEI argues that the due diligence standard is sufficient to protect customers and, therefore, the Commission's references to extenuating circumstances and events beyond the control of the transmission provider should be interpreted to explain some aspects of the due diligence standard, rather than impose a new standard for completion of studies. Joined by Progress Energy, EEI asks the Commission to modify section 19.9(iii) of the *pro forma* OATT to explicitly provide that penalties will be assessed only if the transmission provider fails to complete 90 percent of its studies for non-affiliates within 60 days because of a lack of due diligence or where there are no extenuating circumstances.

731. National Grid seeks similar clarification that the Commission is not moving away from the due diligence standard in favor of an excuse-based standard. National Grid argues that the requirement that transmission providers provide an affirmative excuse to avoid operational penalties for untimely studies is an unexplained departure from precedent and inconsistent with the Commission's reference to the due diligence standard in Order No. 890. National Grid states that the Commission found in Order No. 2003 that financial penalties were not appropriate for late interconnection studies and, instead, required the transmission provider to use due diligence to perform within the specified time frame. National Grid argues that the Commission failed to justify use of a different, excuse-based structure with monetary penalties in the context of studying transmission service requests.

732. National Grid, along with the Washington IOUs, opposes an excuse-based standard, arguing that the transmission provider may not always have a readily articulated excuse for not completing studies on time. National Grid states that transmission providers cannot simply hire and fire planning employees or otherwise redeploy other employees as study queues expand and contract and that, even if they could, the pool of qualified planning engineers is inadequate. Washington IOUs also argue that there are numerous legitimate reasons why a transmission provider might not process a study within the 60-day guideline, including requests by the transmission customer to delay the study process.

733. Several petitioners argue that the Commission should extend by 30 days or 60 days the period within which

studies should be completed. MidAmerican argues that strict adherence to the 60-day target will lead to less complete analyses by limiting the transmission provider's ability to coordinate with neighboring systems and regional reliability organizations, which may be necessary to understand the full effect of a proposed transaction, and forcing the transmission provider to make assumptions regarding the impacts of higher queued requests still in study status. E.ON U.S. similarly argues that the length of a study is influenced by the size and type of the line or substation upgrade required, the limited availability of third-party contractors, and the fact that certain modeling studies can take many weeks to prepare. MidAmerican and E.ON U.S. both argue that internal staff limitations further impact the transmission provider's ability to meet the 60-day target.

734. EEI, MidAmerican, and Southern argue that introduction of conditional firm and modified planning redispatch service will complicate the study process, may lead to an increase in study volume, and ultimately make the 60-day deadline substantially more difficult to meet. EEI and Southern argue that it is arbitrary and capricious for the Commission to acknowledge in Order No. 890 that studying the availability of these products will place increased burdens on transmission provider without addressing the problem by granting transmission providers more time to complete those studies.

735. MidAmerican, Progress Energy and TranServ request clarification regarding when a system impact study is considered complete for purposes of the 60-day due diligence deadline. Progress Energy suggests that failure to complete a study within 60 days should be measured from the projected start date that is included in the applicable study agreement, rather than the date the study agreement is executed, and that the transmission provider must clearly explain the extenuating circumstance to the customer. MidAmerican suggests that the milestone should be the first submission of the study report to the transmission customer because it is customary for transmission providers to provide a copy of the system impact study for customers to review, which may lead to additional analysis or review of potential issues prior to issuing a final system impact study. If provision of the review copy of the system impact study does not satisfy the tariff requirement, MidAmerican contends that transmission providers will simply omit customer review and provide final studies, likely resulting in more disputes between customers and transmission providers. MidAmerican also argues that any delays that occur as a result of review and acceptance of study results due to regional planning process criteria should not subject the transmission provider to penalties. TranServ similarly notes that certain system impact studies are subject to regional coordination review that is out of its control. TranServ contends that a system impact study should be deemed complete when a study report is concurrently posted on the OASIS, provided to the customer for review, and provided for regional coordination.

736. Some petitioners ask that the Commission exempt from potential operational penalties certain types of studies or otherwise confirm that delays in those circumstances will be considered extenuating circumstances. Southern and Washington IOUs ask the Commission to make clear that operational penalties will not apply when the transmission provider and transmission customer expressly agree to a study schedule providing for a study period longer than 60 days. TranServ contends that extension of a study period to allow for clustering of multiple requests from the same transmission customer should be deemed an extenuating circumstance. EEI suggests that studies of the redispatch or conditional firm options be exempted from potential penalties or, at a minimum, that the Commission establish a one-year transition period prior to including such studies.

737. Progress Energy asks that the Commission recognize additional specific examples of possible extenuating circumstances, including: prior submitted generator interconnection queue requests that impact the same interface as transmission service queue requests; multiple transmission service queue requests being submitted within a 60-day period; a higher queued request that is withdrawn after it has been accepted which can cause a restart on subsequent studies that are underway; and a major change in transmission and generation plans of a local or neighboring system that can cause a restart on subsequent studies that are underway.

738. MidAmerican argues that the Commission should remove the penalty provisions for facilities studies requiring major construction or offer customers the option of extending the study period without penalty to the transmission provider where a customer has a desire for an accurate cost and schedule estimate. MidAmerican contends that the 60-day study window is inadequate to fully evaluate all the environmental, cultural, and landowner issues to fully determine the optimum route for a new line. Without knowing what route a line should take, MidAmerican argues that an accurate cost estimate and schedule cannot be prepared for the customer and, in turn, that it is unreasonable to expect a customer to sign a service agreement based on a highly variable cost and schedule estimate. MidAmerican also suggests that, in cases where the transmission service requests are submitted in association with a new generation interconnection request, coordination with the generation interconnection queue should be explicitly allowed. MidAmerican states that, under the Large Generator Interconnection Procedures, the time required to determine the facilities necessary to accommodate a generation interconnection request can exceed 250 days from the date the interconnection request is submitted. MidAmerican contends it is not possible to start the system impact study for the transmission service request until after it is known what the topology of the system will be with the new generating facility and any associated network upgrades and, therefore, the 60-day target should not apply.

739. E.ON U.S. requests clarification of the application of operational penalties to its operations in particular. E.ON U.S. states that it has delegated certain tasks, including the responsibility to perform system impact studies, to an independent transmission organization, *i.e.*, Southwest Power Pool. E.ON U.S. contends that this delegation of responsibility is consistent with or superior to the penalties established in the *pro forma* OATT since it ensures that studies will be performed in a non-discriminatory manner. In the alternative, E.ON U.S. seeks guidance on how, or whether it may influence the length of time it takes Southwest Power Pool to complete system impact studies, so that they are completed within the 60-day due diligence requirement. E.ON U.S. is concerned that it may be responsible for penalties incurred by Southwest Power Pool for failure to complete system impact studies for E.ON U.S. while being prohibited from influencing the manner in which the studies are performed due to the Commission's orders regarding Southwest Power Pool's independence.

740. TDU Systems seek clarification that imposition of an operational penalty on a transmission provider for a late study does not foreclose other

remedies to compensate for any damages arising out of a transmission provider's lack of due diligence, such as, recovery of the incremental cost of purchasing power from the market as well as other direct and consequential damages, if the transmission customer can show it is entitled to further relief. TDU Systems suggest that the Commission explicitly recognize that a transmission provider's failure of performance sufficient to merit the imposition of an operational penalty also falls outside the scope of the indemnification owed by the transmission customer to the transmission provider under OATT section 10.2.

Commission Determination

741. The Commission affirms the decision in Order No. 890 to subject transmission providers to operational penalties when they routinely fail to meet the 60-day due diligence deadlines prescribed in sections 19.2, 19.4, 32.3 and 32.4 of the *pro forma* OATT. As the Commission explained in Order No. 890, transmission providers must have a meaningful stake in meeting study time frames.[288] With the procedural protections adopted by the Commission, the new penalties for late study will ensure that transmission providers have an adequate financial incentive to exercise due diligence in processing service requests in a timely and nondiscriminatory manner.

742. We agree with petitioners that transmission providers should not sacrifice accuracy in order to complete studies within the 60-day due period and that transmission providers may already have an incentive to complete studies quickly in order to increase revenues from transmission service. This does not mean, however, that it is inappropriate to apply penalties in instances when transmission providers repeatedly fail to comply with study deadlines without justification. The notice procedures adopted in Order No. 890 give transmission providers an opportunity to explain why studies have been completed late. As a practical matter, then, late study penalties should only apply to those transmission providers unable to justify their repeated failure to meet deadlines. At the same time, the possibility of penalties will provide appropriate incentives to ensure that transmission providers process studies on a timely and nondiscriminatory basis.

743. In response to concerns regarding application of the due diligence standard, we reiterate that sections 19.3, 19.4, 32.3, and 32.4 of the *pro forma* OATT require transmission providers to use due diligence to meet the 60-day study deadline. The 60-day due diligence deadline serves as a good measure of a transmission provider's use of due diligence since, in our experience, the vast majority of transmission studies can be completed within that period. We recognize, however, that certain transmission studies can present challenges or other circumstances may justify a longer study period. The Commission therefore adopted rules that allow transmission providers to complete studies outside the due diligence deadlines without paying late study penalties. In its notification filing, the transmission provider can explain the extenuating circumstances that lead to delay and, in turn, demonstrate that it has used due diligence in processing the relevant studies notwithstanding its inability to meet the 60-day target. Transmission providers should discuss any factors that they believe are relevant, including reasonable resource limitations, the accommodation of customer requests (including clustering), inter-regional and seams coordination, the scope of particular studies, or fluctuations in study volumes. On review of this information, the Commission will waive application of late study penalties under section 19.9 of the *pro forma* OATT as appropriate. We therefore do not believe any modification to the language of section 19.9 is necessary.

744. We also reject requests to create broad categories of extenuating circumstances that would exempt transmission providers from late study penalties or related posting requirements. Consideration of the particular circumstances causing a transmission provider to repeatedly miss study deadlines is best left to a case-by-case analysis. Again, failure to meet the 60-day due diligence deadlines does not lead unavoidably to late study penalties, regardless of whether the study is related to the new planning redispatch option for long-term point-to-point service, the modified conditional firm option, or any other service request. Granting broad exemptions for any particular types of requests would undermine the Commission's ability to gather information regarding the reasons for processing delays and, in turn, ensure that those delays are justified under the circumstances.

745. We also decline to automatically waive late study penalties for particular types of transmission providers, such as transmission and distribution utilities without a power marketing affiliate, as suggested by NorthWestern, or RTOs and ISOs, as suggested by MISO. The Commission is concerned about potential discrimination in favor of a transmission provider's affiliated customers as well as discrimination between different classes of unaffiliated customers. In response to E.ON U.S., we clarify that delegating to a third party the responsibility for conducting transmission studies does not relieve the transmission provider of its obligation to ensure compliance with sections 19 and 32 of the *pro forma* OATT. Regardless of whether the third-party service provider is under the transmission provider's control, the agreement governing the relationship between the service provider and the transmission provider would establish the service provider's responsibilities and potential liability for failing to meet service obligations. This could include, for example, the responsibility to submit notification filings describing any extenuating circumstances that keep the contractor from meeting deadlines.

746. We disagree that the 60-day due diligence period should be extended simply because there is the possibility of penalties in the event of repeated non-compliance. While we recognize that the timelines we use in Order No. 890 for processing transmission service requests may differ from those we have in place in other settings, the 60-day deadlines have been in place for many years. We continue to believe that 60 days is, on average, sufficient time to complete most transmission studies. As the Commission explained in Order No. 890, and as we reiterate above, transmission providers that are delayed due to the addition of the conditional firm option, modification of planning redispatch, staffing availability, or any other issues are free to raise those issues in their notification filings.[289] We appreciate, and in fact intend, that the possibility of penalties will create added incentives to complete system impact studies and facilities studies within the 60-day due diligence deadlines. It does not follow, however, that the deadlines themselves should change. In order for late study penalties to apply, the transmission provider would have to be out of compliance for at least three quarters after the reforms adopted in Order No. 890 took effect. This gives transmission providers nine months to adjust their operations and reallocate resources as necessary to meet its obligation to process studies on a timely basis.

747. In response to MidAmerican and TranServ, the Commission reiterates its current policy that transmission studies

[288] *See* Order No. 890 at P 1340.

[289] *See id.* at P 1345.

will be deemed complete at the point when the transmission provider returns a final system impact study or facilities study to the transmission customer. Drafts of such studies, whether submitted to regional coordinators or the transmission customer, do not satisfy this threshold because, by definition, they are subject to revision and are incomplete. Allowing study drafts to be considered completed for purposes of the 60-day due diligence deadline would undermine incentives to finalize such studies, leaving transmission customers with little assurance that their transmission requests would be processed in a reasonable time period. We do not mean to discourage, however, consultation with customers or regional coordination. To the extent such activities lead to delays, they should be explained in the notification filing. The Commission clarifies in response to Progress Energy that the 60-day due diligence period starts on the day the transmission study agreement is executed unless the transmission provider and customer agree on an alternate day for the transmission provider to begin the study. While the transmission provider and customer may not alter the length of the study period, they can mutually agree as to the day on which the study begins.

748. Finally, we clarify in response to TDU Systems that payment of a late study penalty by the transmission provider falls outside the scope of the indemnification provided by transmission customers under section 10.2 of the *pro forma* OATT. Similarly, assessment of a late study penalty would not preclude other claims for damages to the extent the transmission provider is liable under relevant legal principles.

(3) Recovery Through Rates

749. In Order No. 890, the Commission prohibited all jurisdictional transmission providers from recovering penalties for late studies from transmission customers. The Commission required non-profit transmission providers to pay late study penalties from sources other than the revenue they collect for sales of transmission service.

Requests for Rehearing and/or Clarification

750. Several petitioners object to the application of operational penalties to RTOs and ISOs and request clarification of the manner in which penalties could be recovered by RTOs and ISOs. MISO argues that RTOs and ISOs should be exempt from the imposition of penalties because the organizations have little or no equity cushion from which to pay penalties and often need to obtain operational/technical information from member transmission owners, over which they have no control, in order to complete studies. MISO argues that, as independent entities, RTOs and ISOs have no incentive to favor one group of customers over another and that the Commission's unsupported reference to competing internal priorities or staffing issues is not a reasoned substitute for the undue discrimination rationale on which the Commission's reforms are based. MISO argues that the distinction between an RTO and a single system transmission provider is particularly acute for MISO, PJM, and Southwest Power Pool, which have been required by the Commission to execute seams operating agreements that require the sharing of planning information.

751. MISO objects to the potential use of funds set aside for salaries or bonuses to pay penalties, suggesting that budget cuts are not an appropriate remedy for staffing issues. MISO contends that RTOs and ISOs should be allowed to recover penalties in rates. MISO states that reliability rules permit RTOs and ISOs to recover their ERO penalties in rates and the same should be allowed for operational penalties. MISO acknowledges that the Commission allowed transmission providers an opportunity to avoid operational penalties by showing that failure to meet the compliance threshold is due to extenuating circumstances, but objects to that process as burdensome. MISO argues that it is unclear what circumstances would be considered extenuating, suggesting that some customers request service well in advance because they are aware of possible delays in performing necessary studies. To the extent the Commission retains financial penalties for RTOs and ISOs, it suggests that delays resulting in no harm to the customer should not be included in the 10 percent threshold.

752. EEI, National Grid, and ATCLLC argue that the Commission first should consider non-monetary penalties for RTOs and ISOs, such as increased oversight, before assessing any monetary penalties. ATCLLC and National Grid contend that using a non-monetary enforcement policy for violations of the OATT would more closely mirror the policy adopted by the Commission with respect to enforcement of reliability standards, as reflected in NERC Sanction Guidelines. National Grid suggests that the Commission not take the next step of imposing monetary penalties (whether operational or civil penalties) on RTOs or ISOs absent extraordinary reasons, such as repeated or willful violations.

753. If monetary penalties are assessed on an RTO or ISO, National Grid argues that the non-profit status of RTOs and ISOs justifies allowing those entities to recover the cost of penalties through rates, provided those costs are allocated to all market participants fairly. ATCLLC and Duke, however, oppose recovery of any operational or civil penalties in the rates of an RTO or ISO. ATCLLC argues that allowing RTOs and ISOs to include penalties in their cost of rendering transmission or market services would defeat the purpose of the penalty. In its view, the pass-through of penalty costs would be tantamount to imposing the financial consequences of an action on parties that did not commit the violation, that may not have any control over the action causing the violation, and who may have been negatively impacted by the violation. Duke asks the Commission to clarify that the other sources of money from which RTOs and ISOs must pay operational or civil penalties do not include any rates collected from customers, including administrative charges, energy charges, or charges for transmission-related services.

Commission Determination

754. The Commission affirms the decision in Order No. 890 to prohibit transmission providers from automatically passing through to transmission customers the cost of late study penalties. The 60-day due diligence standard is in place to protect customers and it would therefore be inappropriate to automatically recover from those customers penalties assessed for non-compliance. We are mindful of the unique operating and budgetary concerns of independent transmission providers with respect to their ability to pay late study penalties and will keep those concerns in mind when reviewing these transmission providers' notification filings. However, as we explain in section III.C.4.c, it would not be appropriate to exempt, on a generic basis, any particular class of transmission providers from the requirement to pay operational penalties.

755. The Commission acknowledged in Order No. 890 that the independence of RTOs and ISOs removes incentives to favor one group of customers over another. Notwithstanding this independence, competing internal policies or staffing issues could lead to particular types of customers being treated differently during the study process. The potential application of penalties for consistently late studies

ensure that the proper incentives are in place to process request studies in a timely and non-discriminatory manner for every customer. The limited ability of an independent transmission provider to absorb late study penalties is more appropriately considered when determining the penalty, if any, that will apply to an RTO or ISO on review of its notification filing, which would not be possible if a blanket exemption were granted.[290]

756. As explained in section III.C.4.c, we decline to state here the particular sources of funds from which an RTO or ISO should pay any late study penalties ultimately imposed. We do clarify, however, the Commission's statement in Order No. 890 that an RTO or ISO may not use revenues from sales of transmission service to pay late study penalties.[291] It may be the case that an RTO's or ISO's only source of funds is from rates collected from jurisdictional transmission customers. The Commission's intent in restricting transmission providers, including RTOs and ISOs, from automatically passing on to customers the costs of late study penalties was to prohibit those transmission providers from designing their rates to accommodate a pass through of the penalties, *i.e.*, effectively including penalties in its cost of service. A transmission provider is permitted to use revenues previously collected under Commission-approved rates to pay late study penalties by reallocating funds as necessary to distribute late study penalty amounts.

757. We clarify in response to MISO that, if the RTO or ISO is unable to identify any appropriate funds from which to pay a late study penalty, the Commission will consider case-specific cost-recover proposals under FPA section 205. As explained above, such proposals should not include mechanisms to automatically pass through to customers any penalties approved to the RTO or ISO.

(4) Clustering Transmission Service Request Studies

758. Although the Commission did not impose, in Order No. 890, a requirement for transmission providers to study transmission requests in a cluster, the Commission did encourage transmission providers to cluster request studies when reasonable. In particular, the Commission directed transmission providers to consider clustering studies if requested to do so by a group of transmission customers and the transmission provider can reasonably accommodate the request. To that end, the Commission required each transmission provider to include tariff language in its compliance filing that describes how it will process a request to cluster studies and how it will structure the transmission customers' obligations when they have joined a cluster.

Requests for Rehearing and/or Clarification

759. TranServ requests clarification that, if the transmission provider receives a large number of study requests from the same customer within a short time period with no other customer requests commingled, it may be prudent to combine these studies into a clustered study group to reduce costs and study queue volumes, even recognizing that such a practice would result in an extended study period.

Commission Determination

760. In Order No. 890, the Commission required transmission providers to study transmission requests in a cluster if the customers involved request the cluster and the transmission provider can reasonably accept the request. The Commission did not preclude transmission providers from clustering additional request studies if they believe it reasonable to do so. Studying transmission service requests in a cluster in some cases can create synergistic benefits, simplify complex, interrelated transmission requests, and help transmission providers reduce study queue backlogs. To the extent a transmission provider wishes to adopt additional procedures governing the clustering of requested studies, it may propose such procedures in a filing under section 205 of the FPA demonstrating that clustering will be implemented in a timely and non-discriminatory fashion.

761. Although we agree that in certain circumstances the time required to process a clustered study group may exceed the time required to study a single transmission request, we do not agree that this should be always be the case. As the Commission explains above, we will not exempt broad categories of extenuating circumstances, such as the clustering of request studies, from the 60-day due diligence deadline.

(5) Standardization of Business Practices for Study Queue Processing

762. The Commission also required transmission providers working through NAESB to develop business practice standards to better coordinate transmission requests across multiple transmission systems. In order to provide guidance to NAESB, the Commission articulated the principles that should govern processing across multiple systems. The Commission further required transmission providers working through NAESB to develop business practice standards to allow a transmission customer to rebid a counteroffer of partial service so the transmission customer can take the same quantity of service for linked transmission service requests across multiple systems. The Commission explained that the transmission customer should not be required to take the same quantity of service across consecutive transmission service requests and, instead, it should simply have the option to do so.

Requests for Rehearing and Clarification

763. TDU Systems argue that the Commission erred by failing either to mandate coordination among transmission providers or to provide the oversight necessary to ensure that NAESB effectively addresses the standards and practices for coordination. TDU Systems contend that transmission customers have experienced denials of service because of differing response times to transmission service requests spanning multiple transmission systems and that a lack of coordination among transmission providers reduces accountability for potentially anti-competitive denials of service. To the extent the Commission relies on business practices by NAESB, TDU Systems contend that the Commission must provide clear deadlines for NAESB to complete the development process for these business practices. TDU Systems argue that failure to establish deadlines in this context, while establishing clear deadlines for the development of ATC-related standards, is arbitrary and capricious.

764. TAPS asks the Commission to articulate more fully the coordination necessary between transmission providers when a customer's request entails use of multiple systems. TAPS notes that the Commission refers in Order No. 890 to coordination of studies across multiple systems, but that coordination may be unnecessary if one of the affected transmission providers conclude that no system impact study is required. TAPS contends there is nonetheless a need to coordinate such requests so that the customer is not required to confirm service on the no-study system before knowing whether service is available on the other piece of the transmission path.

[290] We clarify that, as part of this analysis, we will consider whether the use of non-monetary penalties would be appropriate in the circumstances.

[291] *Id.* at P 1357.

765. TAPS also requests confirmation that, in the event only one of the transmission providers considering a multi-system request determines that a facilities study is necessary, the transmission provider whose system impact study did not lead to a facilities study must await the completion of the other transmission provider's facilities study prior to requiring the customer to commit to the service or lose its queue position. Similarly, TAPS argues that, if both transmission providers find a need to undertake facilities studies, the customer should not be subject to different deadlines for entering into those facilities studies or committing to service after all of the facilities studies are completed.

Commission Determination

766. The Commission affirms the decision in Order No. 890 to rely on the NAESB process to develop business practices to govern the processing of transmission requests across multiple transmission systems. We decline to dictate at this time, beyond those principles outlined in Order No. 890, the particular practices that must be implemented. It is more appropriate to allow transmission providers working through NAESB, in the first instance, to consider how best to ensure coordination across multiple systems. It is also appropriate to give NAESB an open timeframe to develop these standards since they must be broad enough to account for the complexities of coordinating multi-system transmission service requests.[292]

767. The appropriate forum for TDU Systems and TAPS to raise substantive concerns regarding the coordination required for multi-system requests is therefore the NAESB process. If concerns remain at the conclusion of this process, transmission providers and customers alike can bring them to the Commission's attention on review of the NAESB business practices.

(6) Additional Processing Proposals

768. In response to commenter requests, the Commission revised section 17.7 of the *pro forma* OATT so that the transmission provider is able to terminate a request for transmission service if a customer that is extending the commencement of service does not pay the required annual reservation fee within 15 days of notifying the transmission provider that it would like to extend the commencement of service. The Commission denied a request to require transmission providers to accept or deny in all cases non-firm and short-term firm point-to-point transmission service requests solely based on posted ATC, explaining that transmission providers should not be discouraged from making service available when posted ATC is not accurate.

Requests for Rehearing and/or Clarification

769. Southern argues that the Commission should revise the amended provisions of section 17.7 of the *pro forma* OATT to ensure that transmission customers cannot escape their contractual commitments by simply failing to timely make an extension of service payment. Southern contends that the language of section 17.7 of the *pro forma* OATT makes the termination of a customer's reservation mandatory, while the Commission's discussion of that language in Order No. 890 indicated an intention for such termination to be permissive.[293] Southern contends that mandating termination in the event of non-payment would allow customers to easily escape contractual commitments even where the transmission provider has reserved the underlying transmission capacity for that customer. Southern requests that section 17.7 be revised to state: ''If the Transmission Customer does not pay this non-refundable reservation fee within 15 days of notifying the Transmission Provider it intends to extend the commencement of service, then the Transmission Provider may deem the Transmission Customer in breach and may terminate the Transmission Customer's Service Agreement.''

770. Southern also requests clarification that transmission providers are allowed to study and condition a request for extension of service for long-term agreements having a term of less than five years. Southern states that, under the prior rollover policy, it was able to condition the continuation of service beyond the contract term so long as the condition was stated in the service agreement. Once the rollover reforms become effective and the rollover right extends only to contracts of five years or longer, Southern contends that it will no longer evaluate service availability beyond the requested term of service during the system impact and facility studies. Where such service is not available, Southern contends it would not be possible to grant an extension of the commencement date. Southern therefore asks the Commission to allow transmission providers to study, and possibly limit, all requests for extensions of commencement of service for long-term agreements having a term of less than five years. If the Commission declines to grant this request generally, Southern argues that such studies at a minimum should be allowed for extensions of commencement of service for customers having agreements for planning redispatch or conditional firm service. Southern contends there is increased need for continued study regarding the availability of those products, as the Commission recognized by allowing a two-year reassessment period for the products.

771. Powerex repeats its request to require transmission providers to respond to short-term transaction requests based on the ATC quantity posted at the time the request is granted. Powerex contends that allowing transmission providers to grant or deny service inconsistent with posted ATC encourages transmission customers to always have requests pending in the queue and may lead to customers ultimately viewing the transmission provider's actions as discriminatory. Powerex argues that the Commission cited no evidence that its proposal would be unworkable, operationally problematic, or inefficient, nor explained how its ruling is consistent with the emphasis placed on accurate, timely and consistent ATC postings elsewhere in Order No. 890.

772. Powerex also repeats a request to modify the language of sections 17.1 and 17.5 of the *pro forma* OATT to give transmission providers the flexibility to grant short-term transmission service requirements without performing a system impact study.[294] Powerex argues that requiring transmission providers to perform system impact studies to evaluate short-term service requests imposes deadlines that are often unworkable. Powerex also contends that a refusal to modify sections 17.1 and 17.5 would be at odds with the Commission's decision in Entergy Services, Inc.,[295] in which the Commission allowed Entergy to evaluate short-term requests without performing a system impact study. Powerex argues that the ATC-related reforms adopted in Order No. 890 will

[292] NAESB has indicated that business practices governing the coordination of service requests across multiple transmission systems are in development. The Commission requests NAESB to keep us informed regarding the status of developing these and other business practices.

[293] *Citing* Order No. 890 at P 1390.

[294] Powerex initially raised this issue in the context of the definition of a system impact study and, thus, the Commission addressed the argument in section V.D.10 of Order No. 890.

[295] *Entergy Services, Inc.*, 101 FERC ¶ 61,169 (2002).

ensure that this flexibility will not impair system reliability.

Commission Determination

773. The Commission grants rehearing to revise section 17.7 of the *pro forma* OATT in order to define more equitably the rights and obligations of customers failing to make timely payment of deposits in order to extend the commencement of service. Upon further consideration, we conclude that it would be inappropriate for a transmission customer to lose its underlying transmission service agreement simply because it failed to comply with the requirements of extending the service commencement date. We believe that it is more equitable to require those transmission customers who seek an extension of service, but fail to pay the required deposit in a timely fashion, to lose only their option to extend their transmission service start date and not the underlying transmission service agreement.

774. We therefore decline to adopt the language proposed by Southern, since that could still result in the transmission customer losing its entire transmission service agreement based on a technicality. The revised language of section 17.7 will more appropriately resolve Southern's stated concern about a transmission customer's use of the 15-day deadline in section 17.7 of the *pro forma* OATT to escape its underlying transmission service agreement. If a transmission customer fails to make the appropriate payment to extend service, that customer remains obligated to take service under the original terms and conditions of the underlying transmission service agreement.

775. We agree with Southern, however, that transmission providers should have the opportunity to consider the ability to provide service in the event of an extension for commencement of service. Under prior rollover policies, transmission providers considered whether long-term service would continue to be available beyond the original requested term during their initial consideration of the request for service, since transmission providers were required to identify in the initial service agreement any restrictions on the customer's rollover rights. Once the rollover reforms adopted in Order No. 890 become effective, transmission providers will undertake that analysis only for contracts with a term of five years or more. Transmission providers should continue to have the opportunity to consider the availability of extended service for contracts with terms of less than five years once the rollover reforms become effective. We therefore revise section 17.7 of the *pro forma* OATT to make clear that extensions of service are subject to availability. For contracts of five years or longer, we expect that identification of any restrictions on rollover rights in the initial service agreement will continue to serve as corresponding restrictions on the ability of the customer to extend the commencement of service.

776. We affirm the decision in Order No. 890 not to require transmission providers to grant certain short-term transmission service requests based only on posted ATC values. Transmission providers are in the best position to determine how much capacity exists on their system in real-time and, therefore, it would not be appropriate for the Commission to categorically preclude transmission providers from making such short-term allocations on a case-by-case basis. We do not wish to preclude transmission providers from making service available at times when posted ATC is not accurate. The transmission provider nevertheless must act on a non-discriminatory basis when using its discretion to grant service when posted ATC is insufficient. As the Commission stated in Order No. 890, the transmission provider must log such instances as an act of discretion and post the log so that the Commission and customers may monitor the transmission provider's actions.[296]

777. We clarify in response to Powerex that sections 17.1 and 17.5 of the *pro forma* OATT do not require transmission providers to undertake system impact studies for all requests for short-term transmission service. System impact studies are only required if it is necessary to evaluate the impact of the request prior to granting service. While we would expect a transmission provider to use its knowledge of its system, including prior studies and system assessments, to grant short-term requests when possible, the transmission provider must in every instance consider whether a system impact study is in fact required to evaluate the request for transmission service, as the very precedent cited by Powerex contemplates.[297] We recognize that on occasion a study period could exceed the length of service requested by a transmission customer and thereby render moot the transmission service request. As the Commission explained in Order No. 890, however, implementing a generic rule to eliminate or shorten the period for performing system impacts could jeopardize system reliability.[298] We therefore decline to adopt Powerex's suggested revisions to sections 17.1 and 17.5.

b. Reservation Priority

(1) Priority for Pre-Confirmed Requests

778. The Commission determined in Order No. 890 that longer duration service requests will continue to have priority over shorter duration service requests, with pre-confirmation serving as a tie-breaker for requests of equal duration. The Commission further provided that pre-confirmed, non-firm point-to-point transmission service requests and short-term, firm point-to-point transmission service requests would have priority over non-confirmed, non-firm and short-term requests, respectively, of equal duration. Pre-confirmed requests for transmission service will not preempt an equal duration request that has already been confirmed.

779. The Commission also clarified its policies regarding the treatment of pre-confirmed requests in order to address concerns regarding operational difficulties caused by giving priority to such requests. First, the Commission prohibited transmission customers from withdrawing pre-confirmed, non-firm and short-term firm point-to-point transmission service requests prior to when the transmission customer is offered service or a system impact study. Transmission providers shall invalidate, however, a pre-confirmed request at the request of the transmission customer in the very near term following submittal of the request, in the event the transmission customer makes an inadvertent error in submitting its request. Second, the Commission explained that a customer is not bound to take service when the transmission provider counteroffers the customer's initial request, although it is obligated to take service in the event the transmission provider offers the service requested.

Requests for Rehearing and Clarification

780. TranServ objects to the retention of priority for longer-term service, regardless of pre-confirmation status. TranServ maintains that the advantages of longer-term services in the form of redirect opportunities and secondary market sales are sufficient incentives in and of themselves and that the ability to preempt shorter term service is

[296] *See* Order No. 890 at P 1389 (citing 18 CFR 37.6(g)(4)).

[297] *See Entergy Services, Inc.,* 101 FERC ¶ 61,169 at P 9–10 (stating that Entergy would have information to evaluate requests for short-term service without a system impact study ''in most instances'' and should not ''unnecessarily rel[y]'' on system impact studies'').

[298] *See* Order No. 890 at P 1707.

unnecessary to promote longer term sales. TranServ acknowledges that the preemption and matching provisions have been in the *pro forma* OATT since Order No. 888, but questions the extent to which they have been fully implemented into the business practices of all transmission providers. TranServ argues that transmission customers would prefer to have transaction certainty once they have confirmed service instead of remaining in an uncertain, conditional state up until the relevant scheduling deadline. TranServ also suggests that retention of the preemption policy will impede development of the secondary market for transmission capacity, questioning whether customers would see any value in entering into a secondary market purchase that is subject to preemption or understand their rights and obligations, and those of the assignee, in the event preemption occurs.

781. If the Commission retains the priority for longer term service, TranServ requests clarification of how preemption is to be implemented in certain circumstances. TranServ questions whether a reservation for consecutive terms of service is considered ''unconditional'' in its entirety when the first increment of service becomes unconditional. For a reservation for three consecutive days of daily service, TranServ asks whether that entire reservation (three days) is considered unconditional one day prior to the start of service, or whether only the first day of that three-day reservation becomes unconditional and not subject to preemption.

782. Ameren maintains that the Commission should include priority for pre-confirmed long-term firm requests to ensure that long-term uses are allocated to those customers that have the greatest demand. Ameren contends that excluding long-term firm requests from consideration as pre-confirmed requests may distort the transmission service queue and affect existing long-term firm uses of the grid, such as agreements eligible for rollover rights, by triggering the requirement to match a competing request that has not been confirmed. Ameren requests that the Commission require priority for pre-confirmed requests of all durations of firm service or, at a minimum, require that any request that competes with a long-term firm transmission service agreement eligible for rollover must be pre-confirmed.

783. E.ON U.S. argues that it is not clear what happens to a pre-confirmed request if the transmission provider only can provide the requested service if additional facilities are constructed. E.ON U.S. requests clarification whether an offer to provide service if additional facilities are constructed is a counteroffer that allows the customer submitting a pre-confirmed request to decline service.

784. Tenaska requests additional flexibility regarding the withdrawal of pre-confirmed requests. Tenaska suggests that the Commission establish a defined period, up to the point prior to the processing of the request by the transmission provider, during which pre-confirmed, non-firm and short-term firm point-to-point transmission service requests may be withdrawn for any reason and without penalty. Tenaska argues this flexibility is necessary to ensure that point-to-point customers are not competitively disadvantaged vis-a-vis network service customers when obtaining ATC, since network customers pay no additional cost for transmission they cannot use.

785. Southern suggests that the Commission allow transmission providers working through NAESB sufficient time to develop procedures for processing competing pre-confirmed requests, including how a request whose evaluation is in progress should or should not be impacted by a new pre-confirmed request received prior to such evaluation being completed.

Commission Determination

786. The Commission affirms the decision in Order No. 890 to give priority based on pre-confirmed status only to short-term firm and long-term non-firm requests for service. As the Commission explained in Order No. 890, the Commission was mindful that the pre-confirmation process could disrupt the transmission study process, undermine longer-term uses of the transmission system, or disadvantage transmission customers that are not in a position to pre-confirm their requests. Restricting the scope of transmission service requests receiving priority for pre-confirmation status to short-term firm and long-term non-firm service requests is necessary in order to minimize disruptions with existing study procedures and power procurement practices in place for long-term firm service requests. We believe this appropriately balances the need to promote long-term transmission rights against the need for increased certainty for customers seeking shorter-term firm and non-firm service.[299] Similarly, we decline to alter the Commission's long-standing policy of giving longer duration requests for service priority over shorter duration requests. To do so would undermine the Commission's goal of encouraging longer term uses of the transmission system.

787. We clarify in response to E.ON U.S. that, in the event an offer for service on a pre-confirmed request can only be accommodated by additions to the transmission provider's transmission system, the transmission customer may: (1) Take a shorter term of service, if available; (2) agree to undertake any upgrades that may be necessary to accommodated the transmission requests; or (3) decline service. The Commission rejects Tenaska's proposal to adopt a deadline prior to which a transmission customer may withdraw a pre-confirmed transmission service request. Providing an opportunity to pre-confirm applications is intended to reduce overloading of transmission study queues and minimize the amount of transmission requests later withdrawn from the study queue, increasing the efficiency of processing transmission service requests. Allowing transmission customers to withdraw pre-confirmed transmission service requests without reason or penalty as suggested by Tenaska would undermine the very reason pre-confirmation status has been given a priority.

788. We decline Southern's request to extend the effectiveness of the reforms regarding pre-confirmation priority pending development of related business practices by NAESB. We believe that Order No. 890 provides sufficient guidance for transmission providers to implement this priority in advance of any standardization efforts that may be undertaken through the NAESB process.

789. With respect to TranServ's question regarding application of the right of first refusal for eligible customers with requests for service over multiple days, the Commission clarifies that a competing request must exceed the total term of service in order to trigger the right of first refusal. Thus, in order for a competing request of equal price to preempt a reservation for three conservative days of daily service, that request must be for four consecutive days or longer and must be received at least one day before the first day of the original customer's three-day term of service.

790. Upon review of tariff provisions governing pre-confirmation of transmission service requests, the Commission has determined that the language adopted in Order No. 890 did

[299] As we explain in section III.D.2.c, a customer exercising a rollover right is only required to match a *bona fide* competing commitment to take service, evidenced for example by a pre-confirmed transmission request or the execution of a contingent service contract.

not fully capture the Commission's intent of allowing all eligible customers the opportunity to pre-confirm short-term firm and non-firm reservations. As currently written, the language of sections 1.39, 17.2 and 18.2 of the *pro forma* OATT make pre-confirmation available only to those that are already transmission customers, rather than all eligible customers. The Commission has revised those sections of the *pro forma* OATT to more accurately reflect our intent that pre-confirmation service should be available to all eligible customers seeking short-term firm and non-firm transmission services.

(2) Price as a Tie-Breaker

791. In Order No. 890, the Commission added price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service, so that price will serve as a tie breaker after pre-confirmation status. The Commission clarified that, in the event a later queued short-term request for transmission service preempts a conditionally confirmed short-term request for transmission service based on price, the conditionally confirmed request has a right to match the price offer of the later queued request.

Requests for Rehearing and Clarification

792. E.ON U.S. requests clarification that the use of price as a tie-breaker means that a customer that is receiving service and that is not otherwise subject to a discount will receive a reservation priority over one who receives a discount. E.ON U.S. states that transmission service is not provided at market-based rates and, thus, using price as a tie-breaker cannot mean that a customer offering a market-based price is to be rewarded with reservation priority.

Commission Determination

793. We agree with E.ON U.S. that use of price as a tie-breaker does not mean that a customer is offering to be charged a market-based rate by the transmission provider. Under section 13.2 of the *pro forma* OATT, price serves as a tie-breaker among competing service requests of equal duration only when the transmission provider has offered a discount or a ''below ceiling rate'' on transmission service. Transmission providers may not charge rates above those stated in their OATT for primary transmission capacity.[300]

(3) Five-Minute Window for Requests

794. The Commission determined in Order No. 890 that the first-come, first-served policy for transmission service under the *pro forma* OATT should remain largely intact. The Commission allowed, but did not generally require, transmission providers to propose a window within which all transmission service requests the transmission provider receives will be deemed to have been submitted simultaneously. Only transmission providers that have adopted a ''no earlier than'' time for submitting transmission service requests were required to treat transmission service requests received within a specified period of time as having been received simultaneously. The Commission stated that the submittal window for these transmission providers must be open for at least five minutes unless the transmission provider can present a compelling rationale to justify a shorter submittal window. The Commission required these and any other transmission providers deeming requests submitted within a specified period as having been submitted simultaneously to propose a method for allocating transmission capacity if requests submitted within the same time period exceed available capacity.

Requests for Rehearing and Clarification

795. Powerex and Southern protest the Commission's departure from the long-standing first-come, first-served priority scheme. Powerex contends that, of the commenters supporting a simultaneous-priority window, none presented evidence that they were less sophisticated, had fewer financial resources, or had encountered prohibitively high software and other costs associated with operating an efficient transmission reservation desk. Powerex argues that the Commission mischaracterized support for the window proposal, stating that half of the critics of the proposed window provide and/or use transmission predominantly within the Western Interconnection.

796. Powerex, Southern, and Tenaska suggest that use of a simultaneous priority window will lead to implementation and operational problems, requiring transmission providers to allocate transmission capacity among multiple requesting customers, resulting in customers potentially receiving unusable blocks of capacity. Powerex contends that the Commission has relied on first-come, first-served priority in other contexts based on a similar concern that *pro rata* allocation of scarce capacity may result in blocks too small for the customer to use.[301] If the Commission does not grant rehearing on this issue, Southern asks the Commission, at a minimum, to clarify that NAESB will be permitted to address and resolve in a uniform fashion the numerous operational issues associated with treating all requests received within a certain timeframe as having been received simultaneously.

797. Powerex further argues that, with a *pro rata* window approach, transmission customers with multiple affiliates will be able to secure more usable blocks of capacity by pooling their requests through reassignment, while single-entity customers will confront numerous transaction obstacles to obtain a similar result. Powerex again points to precedent in the gas context, arguing that the Commission recognized similar concerns to support a first-come, first-served approach for reserving pipeline capacity.[302] Powerex argues that the Commission failed to address these concerns. Finally, Powerex objects to the Commission's characterization of the first-come, first-served priority structure as arbitrary, arguing that a specified window is equally arbitrary since it separates by a millisecond those that fall within the simultaneous window and those that fall outside.

798. If the Commission declines to grant rehearing of the use of a simultaneous priority window, Powerex requests clarification regarding its implementation. First, Powerex contends that a simultaneous window must commence at the start of the ''no later than'' hour and conclude five minutes later, and not be a ''rolling window'' that groups together service requests submitted within five minutes of each other. Second, Powerex requests clarification that the simultaneous priority window would not apply to hourly transmission service, to the extent it is offered by the transmission provider, arguing that there is insufficient time for customers to monitor the multitude of various transmission providers' windows for hourly requests and that potential *pro rata* allocations of hourly service would have little value to customers.

799. Tenaska similarly argues that the Commission must provide clear, uniform guidance as to what methods will, and will not, be acceptable for allocating transmission capacity when there is insufficient capacity to satisfy requests deemed to have been submitted simultaneously, as well as further guidance regarding the window period

[300] The Commission addresses the reassignment of transmission service in the secondary market in section III.C.3.

[301] *Citing Trailblazer Pipeline Co.,* 108 FERC ¶ 61,049 (2004).

[302] *Citing id.*

that a transmission provider may designate. Tenaska contends that the Commission has given transmission providers too much discretion by allowing them to propose a method for allocating transmission capacity if sufficient capacity is not available to meet all requests submitted within the specified time period. Tenaska argues that such discretion is a potential breeding ground for undue discrimination and, therefore, that the Commission should provide additional guidance to ensure that the methods for allocating transmission capacity minimize the opportunity for gaming.

800. Ameren asks the Commission to clarify that any proposal to voluntarily adopt an equivalent priority standard must be clearly defined and supported. Ameren suggests that an applicant submitting a proposal for a five-minute equivalent priority standard must make clear whether it is proposing to use a rolling five-minute window or whether it will use a series of discrete five-minute windows. Ameren contends the applicant also should be required to clearly explain what sort of tie-breaking mechanisms it will use.

801. EEI asks the Commission to clarify the requirement to adopt a submittal window is not triggered by a ''no earlier than'' time for requests for non-firm service. EEI notes that section 18.3 of the *pro forma* OATT requires all transmission providers to impose limits on how early a request for non-firm service may be submitted. EEI therefore argues that the requirement to adopt a submittal window should apply only to transmission providers that have established a ''no earlier than'' time for requests for firm point-to-point or network service.

Commission Determination

802. The Commission denies rehearing of the Commission's decision in Order No. 890 to require transmission providers that have adopted a ''no earlier than'' time for submitting requests for firm transmission service to treat all requests received within a specified period of time as having been received simultaneously.[303] We agree with petitioners that the Commission's long-standing first-come, first-served policy is a simple and efficient way for transmission providers to allocate firm transmission capacity among competing service requests. For this reason, Order No. 890 generally grants transmission providers the discretion to determine which transmission services, if any, will be subject to a submittal window. The Commission recognized only one exception to this rule: when the transmission provider has established dates before which requests for firm transmission service will not be accepted.

803. As the Commission explained in Order No. 890, the first-come, first-served policy can disadvantage certain transmission customers when a ''no earlier than'' restriction is in place.[304] Such a restriction forces transmission customers competing for transmission capacity to precisely time their requests for service such that they are received after the ''no earlier than'' time, yet before other customers. This has the potential of disadvantaging transmission customers that are less sophisticated and have fewer financial resources. The Commission stated in Order No. 890 that, when considering requests for firm transmission service received after the ''no earlier than'' time has expired, there is no meaningful difference between those received seconds ahead of another because one customer's computer is slower than another and no petitioner argues otherwise on rehearing.[305]

804. We clarify in response to Ameren and Powerex that each transmission provider has discretion to determine how its submittal window will be implemented, including the point at which the window goes into effect. Although the Commission agrees with Powerex, in principle, that it would be logical for submittal windows to begin on the first minute of the ''no earlier than'' time, we will not categorically dismiss alternatives to this arrangement since these procedures are best reviewed on a case-by-case basis. Similarly, any transmission provider that has implemented hourly firm point-to-point service should address how the submittal window would be implemented for that service, including any limitations on the use of a submittal window for that product. It is more appropriate for the Commission to consider customer concerns regarding use of a submittal window for hourly firm transmission service in the context of the transmission provider's particular proposal.

805. The Commission recognizes that developing methods to allocate capacity among requests received during a submittal window may require detailed procedures, particularly when transmission requests received simultaneously exceed available capacity. As the Commission explained in Order No. 890, however, we believe that each transmission provider is in the best position to develop allocation procedures that are suitable for its system. This does not preclude transmission providers from working through NAESB to develop standardized practices, as suggested by Southern. For example, as we pointed out in Order No. 890, allocation methods such as that used by PJM to allocate monthly firm point-to-point transmission service could provide useful guidance in developing general allocation procedures.[306]

806. The Commission disagrees with Tenaska that allowing transmission providers to develop a methodology to allocate insufficient capacity will lead to undue discrimination. As Ameren suggests, each transmission provider must clearly define and support its allocation methodology in its tariff and, thus, customers can raise any concerns regarding the potential for discrimination during the Commission's review of the relevant tariff language. Once the tariff language is in place, transmission customers can, and should, bring to the Commission's attention any failure by the transmission provider to follow its tariff. While the Commission could remove transmission provider discretion in this area by adopting a single, one-size-fits-all approach, such as a mandatory *pro rata* distribution methodology, this approach may not produce the best result in all cases. As the very precedent cited by petitioners acknowledges, every allocation methodology has advantages and disadvantages.[307] We reiterate our belief that transmission providers are in the best position to determine which allocation mechanism works best for their systems.

(4) Right of First Refusal and Preemption

807. The Commission declined in Order No. 890 to otherwise change the ''first come, first served'' nature of the

[303] We agree with EEI that the requirement to establish a submittal window applies to those transmission providers that have adopted a ''no earlier than'' time for the submission of firm point-to-point or network service. The *pro forma* OATT contains a ''no earlier than'' time that applies to requests for non-firm point-to-point service, which we do not intend to trigger the requirement to establish a submittal window.

[304] *See* Order No. 890 at P 1419.

[305] *Id.*

[306] *See id.* at P 1422.

[307] *See Trailblazer Pipeline Co.,* 108 FERC ¶ 61,049 at P 41. The Commission in that case accepted a pipeline's proposal not to use *pro rata* allocations in the event tie breaking was necessary out of a concern that resulting amounts of capacity would be too small to be of real use to a shipper. Shippers, however, had argued for use of *pro rata* allocations to increase the number of parties that could serve a market. Based on the circumstances of that case, the Commission accepted the proposal to use a first-in-time tiebreaking methodology. It does not follow, however, that use of a *pro rata* allocation would be inappropriate in all circumstances.

reservation process or right of first refusal process. The Commission explained that, when a longer-term request seeks capacity allocated to multiple shorter-term requests, the shorter-term customers should have simultaneous opportunities to exercise the right of first refusal. The Commission also stated that, to minimize the potential for gaming, a preempting longer request must be for a fixed capacity over the term of the request. The Commission also revised section 13.2(iii) of the *pro forma* OATT to more clearly distinguish between the use of the terms ''request'' and ''reservation'' for purposes of administering the right of first refusal.

Requests for Rehearing and Clarification

808. TranServ contends that the Commission did not fully address in Order No. 890 the procedures governing the right of first refusal competition and its potential for gaming. If a longer-term request initiates a right of first refusal competition among multiple shorter-term customers, TranServ requests clarification of whether there should be rounds of bidding and, if so, what the timing of that process should be. TranServ also asks what should happen in the event that a longer duration (not pre-confirmed) request is withdrawn in the middle of a competition, *i.e.*, whether those customers that opted to match are allowed out of their longer duration reservations and whether those that opted not to match are re-instated to their original capacity. TranServ suggests that, before any preemptions are initiated, the longer duration, higher priority request must be confirmed and locked in with the competing customer before turning to the right of first refusal rights holders and seeking their intent to match to preserve their service priority. In addition to locking in the longer duration customer prior to initiating preemption and right of first refusal, TranServ argues that the transmission provider should be required to provide a ''counter-offer'' matching request to the customer being preempted that they may then elect to ignore or withdraw, or confirm to retain their service priority. TranServ further questions what the transmission provider's obligation is if the customer being preempted exercises its right of first refusal by submitting a longer duration request which cannot be granted without preemption of yet another request.

809. TranServ also questions implementation of the right of first refusal in the event transmission capacity is reassigned. Assuming that a customer with a confirmed reservation for one week resells capacity for one day, TranServ asks whether the reseller, the assignee, or both have responsibility to match a competing longer-term request received by the transmission provider. TranServ states that this issue was considered by NAESB during WEQ discussions and that, during those discussions, there was serious consideration given to not allowing the resale of short-term firm prior to its unconditional deadline.

810. TranServ further questions what a shorter-term transmission customer's obligation is if the longer-term service request only preempts a portion of the short-term customer's service. TranServ suggests that the term ''match'' in such instances be limited to an exact match of duration with no option for the preempted customer to go beyond those bounds and that the capacity of the match should be in the amount that would need to be recalled from the preempted customer to satisfy the longer duration request.

811. Duke argues that the right of first refusal regime for transactions as short as one day for firm and one hour for non-firm is overly complicated and will leave customers confused and unsatisfied as to whether and when they can be assured that they have secured transmission capacity. Duke provides detailed hypotheticals of the right of first refusal competition process, arguing that the process is cumbersome and could lead to anomalous and unwarranted outcomes. Duke urges that the Commission place the following limits on the right of first refusal: Require that matching requests be pre-confirmed and at full tariff price, and that they be for the same amount (MW) and duration as the competing requests; and, provide that rights of first refusal are only offered when there is no impact on reservations that are not on constrained interfaces. With these limitations in place, Duke contends that the transmission provider will not have had to entertain multiple right of first refusal rounds that in some instances may leave capacity on the table and force customers to buy more service than they may have required.

812. Bonneville seeks clarification as to how duration, pre-confirmation status, price and time of response should be used to determine the order in which the multiple, preempted shorter-term requests may exercise the right of first refusal. By providing several hypotheticals, Bonneville states that it cannot envision a circumstance in which a right of first refusal is offered to a request when the transmission provider does not have capacity to satisfy that request. Bonneville requests that the Commission either delete the two sentences in section 13.2(iii) of the *pro forma* OATT concerning this issue or clarify how the transmission provider is expected to apply them.

813. Bonneville also requests clarification regarding which customers have a right of first refusal under section 13.2 of the *pro forma* OATT. Although the Commission amended the second sentence in section 13.2(iii) of the *pro forma* OATT to grant eligible customers with a ''reservation'' a right of first refusal to match longer-term ''requests,'' other sentences in that section still refer to preemption of shorter-term ''requests'' for service instead of ''reservations.'' Bonneville states that this suggests that shorter-term requests maintain a right of first refusal. Bonneville also contends that the first sentence of section 13.2(iii), providing that ''requests'' for longer term service may preempt ''requests for shorter term service'' up to specified deadlines, suggests that a longer duration request simply preempts a shorter duration request, which is not offered a right of first refusal. Bonneville argues that this would violate the first-come, first-served rule, yet if the longer duration request is offered a right of first refusal, it would contradict the amended language of section 13.2(iii), under which only longer duration ''reservations'' have a right of first refusal.

Commission Determination

814. The Commission affirms the decision in Order No. 890 not to change the ''first-come, first served'' nature of the reservation process and the right of first refusal. These policies have worked well in the past and, as we explain in Order No. 890, benefit transmission providers and customers alike by facilitating the administration of the reservation process and removing confusion about how to comply.

815. We disagree with Duke and TranServ that the right of first refusal policies should be revised based on complex hypotheticals involving the preemption of multiple short-term reservations. The complexities pointed to by these commenters do not by themselves warrant changing the right of first refusal rule. Even though we recognize the potential for complexities to arise under the right of first refusal rule, we believe them to be relatively limited. In the off-chance that multiple eligible customers with short-term reservations choose to exercise their right of first refusal for the same capacity simultaneously, the Commission believes that they should have a right to do so.

816. We therefore decline to expand upon the language of the *pro forma*

OATT to account for every factual scenario that could arise under sections 13.2 and 14.2 of the *pro forma* OATT. Sections 13.2 and 14.2 of the *pro forma* OATT set forth adequate guidance for transmission providers to fairly administer competing requests, including the priorities for determining which reservations or requests trump one another as well as the timeframes for eligible customers to respond to competing requests. As noted above, we recognize that certain unique cases can present difficult allocation issues, but conclude that these extreme cases arise infrequently in the normal course of business. In the vast majority of cases, we believe the right of first refusal rules are efficient and easy to administer without further amending the governing tariff language, as Bonneville and Southern suggest.

817. To the extent necessary, the Commission clarifies that a ''competing request'' under sections 13.2 and 14.2 of the *pro forma* OATT may include a transmission service request that overlaps with only part of another existing transmission service reservation since both requests cannot be granted simultaneously. Accordingly, a ''competing request'' for purposes of sections 13.2 and 14.2 may also include a transmission service request for which transmission capacity cannot be accommodated without preempting one or more existing transmission reservations of parts thereof.

818. In response to TranServ and Duke, we clarify that sections 13.2 and 14.2 allow an eligible customer to retain its original reservation by matching the competing service request's cost or duration terms exactly or by exceeding one or more of the terms of a competing transmission service request. Since any ''match'' by an eligible customer in response to a potentially preempting request, by definition, either exceeds the costs, duration or both of the eligible customer's original reservation, we do not believe eligible customers opting to match a competing request have a strong incentive, if any, to ''match'' a competing request with terms that exceed the competing request. Nevertheless, we do not see any harm resulting from a match that exceeds the exact terms of a competing request and therefore believe it would not be appropriate to preclude the ability of eligible customers to make such a request.

819. With regard to reassignments of capacity in the secondary market, we clarify that the associated right of first refusal under sections 13.2 and 14.2 of the *pro forma* OATT to match a competing transmission service request applies to the primary transmission service, not the reassignment of scheduling rights. Using TranServ's example, the reassignment of one day of a customer's weekly service would not cause the assignor or the assignee to match a competing three day request for service since the initial one week reservation already exceeded the competing request. The fact that one day of service has been reassigned does not alter the assignor's entitlement to use service for the remaining week reserved.

820. Finally, we grant rehearing to revise sections 13.2 and 14.2 of the *pro forma* OATT to clarify, as Bonneville requests, the terms and obligations of sections 13.2 and 14.2 of the *pro forma* OATT.

5. Designation of Network Resources

821. In Order No. 890, the Commission addressed certain issues with respect to the qualification, documentation and undesignation of resources by a network customer. A number of petitioners request rehearing and clarification of the Commission's rulings on these issues. We address each of these issues in turn.

a. Qualification as a Network Resource

(1) LD Contracts

822. In Order No. 890, the Commission affirmed its existing policy that a power purchase agreement may be designated as a network resource provided it is not interruptible for economic reasons, does not allow the seller to fail to perform under the contract for economic reasons, and requires the network customer to pay for the purchase. The Commission concluded that power purchases with a firm liquidated damages (LD) provision may be eligible for designation as a network resource if the contract obligates the supplier, in the case of interruption for reasons other than force majeure, to make the aggrieved buyer financially whole by reimbursing them for the additional costs, if any, of replacement power. The Commission found that the ''make whole'' LD provisions in the EEI firm LD product and the WSPP Schedule C agreement satisfy this requirement.[308]

[308] The Commission further concluded that the WSPP Schedule C agreement appeared to allow interruptions for reasons other than reliability and, as a result, was ineligible for designation as a network resource. The Commission exercised its discretion not to invalidate existing designations of the WSPP Schedule C agreement except under certain conditions. WSPP subsequently amended the Schedule C agreement to expressly prohibit interruptions for reasons other than reliability. *See Western Systems Power Pool,* 119 FERC ¶ 61,123 (2007).

Requests for Rehearing and Clarification

823. NCPA contends that the EEI Firm LD Product does not provide recovery for certain types of penalties that a buyer may incur as a result of non-delivery and, therefore, does not make buyers sufficiently whole to justify designation as a network resource. NCPA states that Section 1.51 of the EEI Firm LD Product prohibits the reimbursement price from including ''any penalties, ratcheted demand or similar charges.'' NCPA states that its contract with the California ISO provides for significant penalties if NCPA operates outside of its deviation band, but there is no avenue under the EEI Firm LD Product to recover those costs if occasioned by a seller's failure to deliver.

824. NCPA also contends that the WSPP Schedule C contract fails to explicitly allow buyers to recover their costs if they decide to cover a non-delivery by running their own more expensive generation. NCPA states that the issue has been discussed at WSPP meetings, but there appears to be no clear consensus that sellers are obligated to pay compensation for internal generation under the current language of the agreement when it is more expensive than the market cost of power. NCPA argues that this interpretation could be particularly problematic for entities such as NCPA, as NCPA may prefer to run even very expensive generation to avoid penalties imposed by the California ISO.

825. NCPA argues that the Commission established a clear and straightforward standard that an LD clause was acceptable if it required the buyer to be made whole in the event of a failure to deliver. NCPA argues that the Commission can resolve the factual issues by directing that these form contracts be amended to require sellers who elect not to deliver (other than for force majeure) to make the buyer whole in all respects, including contractual or market penalties and the costs of the buyer operating its own resources.

826. Ameren argues that the Commission's decision that purchase agreements containing make whole LD provisions can qualify as network resources ignores reliability. Ameren maintains that the key issue is whether such LD products can function as a resource to provide power, not whether the power purchaser will be adequately compensated in the event of a breach. Even with a make whole payment provision in place, Ameren argues that it may still be in the economic interest of the seller to interrupt delivery. While the Commission has appropriately

recognized that this self-interest warrants finding that other types of LD contracts cannot be designated as network resources, Ameren contends that the Commission fails to explain why it should not apply the same standard to purchase agreements with make whole LD provisions.

827. Ameren also expresses concern that purchase agreements with make whole LD provisions may be double-counted when determining capacity, resulting in inadequate physical supplies to meet the simultaneous capacity needs of all purchasers in the event replacement power is needed. Ameren argues that allowing these types of contracts to qualify as network resources is inconsistent with the *pro forma* OATT because under such contracts there are no specific resources that can be called on. Ameren questions whether LD products are sufficiently firm to meet the applicable NERC or regional reliability council requirements for firm resources or as capacity resources.

828. PJM raises a similar concern, asking the Commission to confirm that firm power purchase agreements with make whole LD provisions do not qualify as capacity resources in the PJM region even if they can be designated as network resources under the *pro forma* OATT. PJM argues that service as a capacity resource in the PJM region raises different considerations than those addressed in Order No. 890.

829. Noting that parties often modify form agreements to suit their particular transactions, Duke requests clarification that a purchase based on the EEI Master Agreement qualifies as a designated network resource only to the extent that the network customer has, in fact, contracted for a firm resource that may be interrupted only for reliability purposes. Duke also requests clarification that an agreement that is not modeled after the EEI Master Agreement will qualify as a designated network resource only if it provides for delivery of a product similar to the EEI Firm LD Product (*i.e.*, it cannot be interrupted for economic reasons).

830. EPSA requests clarification that the Commission's statement in Order No. 890 that firm LD contracts create for the buyer a contractual right to generation was not intended to require that a firm LD contract include a contractual right to the output of a specific generating facility.

831. PNM seeks confirmation that a particular long-term power purchase agreement between itself and Southwestern Public Service Company (SPS) is eligible for designation as a network resource. While the terms of this agreement allow for a specified level of curtailment by SPS each month for any reason, the operating procedures governing the agreement provide for curtailment and interruption only for system emergencies. PNM argues that this agreement is therefore sufficiently firm to be designated as a network resource.[309]

Commission Determination

832. The Commission affirms the finding in Order No. 890 that the make whole LD provisions in the EEI firm LD product and the WSPP Schedule C agreement are sufficiently firm to make those agreements eligible for designation as a network resource. In Order No. 890, the Commission distinguished between LD provisions that make the aggrieved buyer financially whole by reimbursing the additional costs, if any, of replacement power and LD provisions that establish penalties at a fixed-dollar amount, cap penalties at some level, or are otherwise not equivalent to a general make whole provision.[310] The Commission explained that, under the latter type of LD provision, the seller need only compare its savings from interruption with the specified LD penalty when deciding whether to interrupt. The EEI firm LD product and the WSPP Schedule C agreement make the buyer adequately whole and, therefore, appropriately qualify for designation as a network resource.

833. With respect to the EEI firm LD product, section 1.51 of the EEI Master Agreement defines the replacement price as either the prevailing market price or, at the buyer's option, the price at which the buyer purchases a replacement product plus costs reasonably incurred in purchasing the substitute product and any reasonably incurred transmission charges to deliver the product. While the replacement price does not exclude penalties, ratcheted demand, or similar charges, as NCPA points out, that does not mean a supplier has inadequate incentives to deliver under the contract. The aggrieved buyer is explicitly allowed to cover the costs reasonably incurred to purchase a substitute product and, therefore, the seller must take into consideration the buyer's actual cost of replacement power, which is our principal concern.

834. With respect to the WSPP Schedule C product, the Commission did not require that contracts make the buyer more than whole in the event it chooses not to purchase less expensive energy available in the market. Again, the Commission is concerned that suppliers providing resources that have been designated by network customers take into consideration the cost of replacing that power should the supplier decide to interrupt. It is therefore adequate for a firm LD contract, such as the WSPP Schedule C agreement, to provide for recovery of the market price of replacement power in the event the buyer decides to run its more expensive generation to cover the interruption.

835. We disagree with Ameren that allowing power purchase agreements containing make whole LD provisions to qualify for designation as network resources will compromise reliability. Firm energy purchases need not be backed by capacity to qualify as network resources since they are by definition firm, consistent with the Commission's finding in *Illinois Power*.[311] We appreciate Ameren's concerns that system reliability be maintained and would not expect double-counting of supplies to result from our designation rules. The proper mechanism for addressing system reliability is through the reliability standards, and not through restrictions on eligibility for network resource status. The requirements for eligibility for network resource status are intended to provide the proper incentives to network customers designating network resources, and not to replace or replicate reliability requirements.

836. Our decision is not, as Ameren claims, inconsistent with the structure of the *pro forma* OATT. As the Commission acknowledged in Order No. 890, there may be situations in which the supplier of a firm LD product is presented with a net financial gain and has an incentive to interrupt, but those incentives are similar to those faced by the owner of a generating unit that has been designated as a network resource.[312] Ameren offers no reasons to require power purchase agreements not tied to a particular generating unit to be more firm than those that are in order to serve as a network resource under the *pro forma* OATT.

837. We clarify in response to Duke that we are not concerned with the particular form used to contract for resources. Each power purchase agreement designated as a network resource must meet the relevant requirements. Whether a contract meets

[309] *Citing Consolidated Edison* v. *Pub. Serv. Elec. & Gas Co.,* 101 FERC ¶ 61,282 (2002).

[310] *See* Order No. 890 at P 1453.

[311] *Illinois Power Co.,* 102 FERC ¶ 61,257 at P 14 (2003), *reh'g denied,* 108 FERC ¶ 61,175 (2004) (*Illinois Power*).

[312] *See* Order No. 890 at P 1454.

these requirements by being modeled after any specific form contract has no bearing on whether the contract is eligible for designation as a network resource. Consistent with *Illinois Power*, a firm LD contract need not represent a contractual right to the output of any specific generating facility. Whether or not such power purchase agreements may serve as a capacity resource under PJM's Reliability Pricing Model (RPM) is governed by the relevant RPM rules adopted by PJM, which were not addressed in Order No. 890.

838. In response to PNM, we decline here to rule on whether a particular purchase qualifies as a network resource because the contract is not before us in this rulemaking. We reiterate, however, that power purchase agreements that are not interruptible for economic reasons may qualify for designation as a network resource. If the binding rules governing a particular agreement allow the seller to curtail or interrupt service only for system emergencies, then that agreement would be eligible for designation as a network resource, provided it complied with the remaining requirements of section 29.2(v) of the *pro forma* OATT.

(2) Off-System Resources

839. In order to ensure that transmission providers have sufficient information to determine the effect on ATC associated with the designation of an off-system network resource, the Commission in Order No. 890 modified section 29.2(v) of the *pro forma* OATT to specify exactly what information must be provided to designate an off-system network resource. As revised by Order No. 890, section 29.2(v) of the *pro forma* OATT requires the following information to be provided with the request and posted on OASIS when designating an off-system resource: (1) Identification of the resource as an off-system resource; (2) amount of power to which the customer has rights; (3) identification of the control area from which the power will originate; (4) delivery point(s) to the transmission providers' transmission system; and (5) transmission arrangements on the external transmission system(s). Additionally, Order No. 890 revised section 29.2(v) of the *pro forma* OATT to require that the following information be provided with off-system designations, but that such information must be masked on OASIS to prevent the release of commercially sensitive information including (1) any operating restrictions (periods of restricted operation, maintenance schedules, minimum loading level of resource, normal operating level of resource); and (2) approximate variable generating cost ($/MWH) for redispatch computations.

Requests for Rehearing and Clarification

840. Duke argues that the Commission's finding that network customers need only identify the control area from which power will originate for an off-system resource is inappropriate in an era in which many control areas encompass the transmission systems of multiple operating companies. Duke requests rehearing, arguing that the Commission should require network customers to provide more specific information for multi-company systems (like Southern) or for ISOs or RTOs. Duke argues that designations such as "the Southern system" or "the PJM system" do not provide sufficient granularity to accurately model a transaction. Duke maintains that a network customer should at least be required to specify the transmission system (*e.g.*, Georgia Power Company for Southern, or Dominion Virginia Power Company for PJM) from which the power will originate.

841. Duke acknowledges that the Commission stated in Order No. 890 that transmission providers could seek amendments to their OATT via an FPA section 205 filing if they believe that they face unique circumstances that require deviations from the *pro forma* OATT to require additional granularity in order to allow them to determine the effects of designating network resources on ATC. Duke argues that this is an inadequate response to the problem, stating that the standard for receiving Commission approval of a variation from the *pro forma* OATT has proved to be a significant bar. Duke also argues that transmission providers could undermine consistency by developing different manners in which to study and analyze such designations. Instead, Duke argues, this issue ought to be resolved "up front" and on a consistent basis, rather than in subsequent case-by-case skirmishes that may not provide guidance for future disagreements.

842. TDU Systems disagree with Duke in their post-technical conference comments, arguing that the requirement to identify the control area within which an off-system resource is located provides the appropriate balance. TDU Systems contend that identification of the control area allows control area operators to calculate the effects on ATC of the designation of an off-system resource while protecting commercially sensitive information about the specific location of a customer's generation resources. Southern agrees that (at least in the Eastern Interconnection) requiring the identification of the "control area(s)" gives the transmission provider sufficient information to reliably plan its system while also providing the market with the flexibility afforded by such off-system seller's choice contracts.

843. Several petitioners request clarification that specification of the control area is not required within purchase agreements for generators located off-system.[313] These petitioners argue that only the actual delivery point for power (which could be a physical resource, a liquid trading hub, and interface point, or some other location) is necessary for transmission system modeling purposes. Information about the originating control area, they contend, is almost never known with certainty at the time the request for designation as a network resource is made and, therefore, requiring such specificity will effectively invalidate such contracts as network resources. Financial Service Joint Requestors and Idaho Power contend that such a requirement could have serious adverse effects on liquidity, competition, and risk management by limiting the ability of marketers to participate in those markets, restricting resource options for LSEs. Financial Service Joint Requestors maintain that participation in the market by companies like its members augments the number of highly creditworthy counterparties willing and able to supply power over mid-to-long tenors to LSEs.

844. In their post-technical conference comments, Financial Service Joint Requestors argue that the Final Rule's acceptance of LD contracts conflicts with the requirement in section 29.2(v) to specify the control area(s) from which the power is sourced, since an LD contract may not provide that information. Financial Service Joint Requestors also argue that Order No. 890 could be interpreted to allow a contract to qualify as a network resource by identifying multiple control areas of origin of the resource, although not the resource itself. Financial Service Joint Requestors state that there is likely to be a wide range of control areas from which power might ultimately be sourced and listing each and every possible originating control area (such

[313] *E.g.*, Financial Service Joint Requestors, Idaho Power, Washington IOUs, and Morgan Stanley, joined by Barrick Goldstrike Mines in its post-technical conference comments. Washington IOUs also argues that the requirement to identify the originating control area "constitutes a direct restriction on the ability of a utility to serve its bundled retail load, and thus violates the limitations on the Commission's jurisdiction over transmission in bundled retail transaction, citing *Northern States Power Co.* v. *FERC,* 176 F.3d 1090 (8th Cir. 1999) and Order No. 890 at P 92–94.

as listing all 33 control areas in the Western Interconnection) seems to be unduly burdensome and cumbersome.

845. APS and EEI, and Financial Service Joint Requestors, joined by Southwestern Utilities in their post-technical conference comments, argue that transmission providers should have discretion to waive the requirement to provide originating control area information for proposed network resources when such information is not needed or is not meaningful for determining impacts on ATC. APS and EEI state that it uses an approved rated path methodology to determine ATC, under which the control area of an off-system purchase delivered to one of its liquid trading hub border interfaces (Palo Verde or Four Corners) has no effect on ATC calculations. APS and EEI state that this contrasts with a flow-based ATC methodology, where the specification of the originating control area can affect the ATC on a transmission provider's system and, therefore, be necessary to calculate ATC. APS and EEI argue that requiring the source control area for all purchased power network resources will significantly reduce the liquidity of physical power markets at Palo Verde and potentially elsewhere in the West. APS and EEI argue that concerns about discrimination could be addressed by directing transmission providers to post a nondiscriminatory policy on its OASIS or directing NAESB to include this issue in its business practices.

846. APS and EEI, and Southwestern Utilities agree, in their post-technical conference comments, that the Eastern and Western Interconnections have very different physical configurations, operating modes and planning modes that have implications for the Commission's rules for designating off-system network resources. In the Eastern Interconnect, EEI argues, contract paths have little bearing on how electrons actually flow, and thus it is critical for transmission planners to know the location, at least at the control area level, of the generation when reviewing requests to designate network resources. In the Western Interconnection, which uses a rated path ATC calculation methodology, APS and EEI, and Southwestern Utilities argue that identification of the source generation for an off-system resource is not important. EEI explains that the physical layout in the West is more of a hub-and-spoke model where the only information required to evaluate a request to designate a network resource is the point at which power is delivered (often a trading hub). For these reasons, EEI argues, seller's choice contracts are not appropriate for network resource status in the Eastern Interconnection, but work well in the Western Interconnection.

847. Pacific Northwest IOUs also agree, in their post-technical conference comments, that it is not necessary in the Western Interconnection for a transmission provider to know the source control area of a remote resource in order to determine its effect on ATC, since WECC path ratings incorporate parallel flows and other operational conditions. Pacific Northwest IOUs state that it is only necessary for a transmission provider in the WECC to know the border location at which power will be delivered to its system in order to determine the effect of the designation on ATC.

848. Morgan Stanley similarly argues, in its post-technical conference comments, that, at a minimum, source control area information for network resources should not be required in control areas where participants agree that such information is not needed for planning purposes. Morgan Stanley suggests that the Commission should create a default approach that explicitly allows designations for off-system network resources to not specify the resource location.

849. APS and EEI state, in its post-technical conference comments, that the kinds of seller's choice contracts at issue (the WSPP Schedule C contracts) are firm, physical contracts that require a seller to deliver power at a specified location. Such contracts, APS and EEI argue, are an important resource for most network customers, because they are not unit contingent, and so sellers must find alternative sources of power and continue to perform even in the event of an outage of a particular generator. These contracts, APS and EEI contend, are more dependable than contracts that specify a specific generator or control area.

850. APS and EEI further contend that allowing flexibility of supply when it does not adversely affect the transmission provider is critical to maintaining liquid power markets in the West. The types of contracts which are at issue, particularly when they are executed with banks, allow physical transactions that could not otherwise occur due to credit quality issues. If the banks conclude that the regulatory constraints are too limiting and choose to move to a financial rather than a physical approach to trading power, an important market, that is currently available to APS and their customers, will be adversely affected.

851. MISO and Duke oppose allowing a seller's choice contract that does not meet all of the section 29.2 requirements to qualify as a designated network resource. MISO argues that the specification of the origin of supply resources or control area improves reliability in a tightly interconnected grid. Duke agrees that, as amended, section 29.2(v) appropriately requires identification of the control area(s) from which the power will originate. Duke argues, however, that there is a facial conflict between this tariff requirement and the preamble, which indicates that off-system seller's choice contracts may be designated network resources. Duke maintains that, unlike a system sale that designated a control area from which the power will originate, a seller's choice contract does not require that power actually originate from the control area designated.

852. Southern notes, in its post-technical conference comments, that the more information that can be provided to the transmission provider, the more accurately it can model its system and, in turn, calculate ATC. Thus, Southern requests clarification that network customers that have designated such an off-system seller's choice contract as a network resource should provide to the transmission provider as much information as the customer has regarding the actual, underlying generating facilities from which the power will be sourced.

853. On rehearing, TDU Systems request clarification that a ''delivery point'' as contemplated by section 29.2(v) of the *pro forma* OATT includes any point on an interface where deliveries are made. TDU Systems argue that it is common in the industry to purchase a system product from off-system and deliver that product to any interconnection point on the interface between the system where the customer's native load is embedded and the system in which the generation is sourced. TDU Systems contend that this is how the term ''delivery point'' is used throughout the industry generally and, in particular, in the NAESB WEQ Glossary Subcommittee's Preliminary Draft Glossary which states that ''a delivery point can be a delivery node, an aggregation of delivery nodes, an interface or trading hub.'' TDU Systems contend that NERC's Glossary of Terms Used in Reliability Standards similarly contemplates that a delivery point may include an interface, defining ''Point of Delivery'' as ''a location * * * where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.'' TDU Systems further argue that current RTO markets embrace the concept of interfaces as delivery points, referring to a statement in section 30.2

of the PJM OATT that ''in the event that the Network Resource to be designated will use interface capacity'' contemplates interfaces as delivery points.

854. Several post-technical conference comments raised questions regarding the need to specify a firm transmission path for the upstream delivery of off-system firm LD contracts designated as network resources.[314] Morgan Stanley argues that sellers of firm LD contracts typically hedge the risk of non-delivery by purchasing a portfolio of paths and sources for supply. If a non-firm path is available that can enable delivery of power used to source a designated network resource, Morgan Stanley contends that the use of that path should be an option for the seller. Morgan Stanley maintains that its experience has shown that firm transmission is often no more reliable than non-firm transmission and is often less reliable. By utilizing more flow options, especially during high-load periods, Morgan Stanley argues that existing transmission capacity is better utilized, as opposed to forcing users into arbitrary firm paths.

855. Southwestern Utilities similarly request that network customers only be required to specify transmission arrangements on external systems from the point at which power is contractually received to the delivery point specified on the transmission provider's transmission system, rather than from the source generator or control area. Sellers of firm LD contracts, Southwestern Utilities argue, would frequently not be able to provide a description of the upstream transmission arrangements on external transmission systems at the time the sale to a network customer is made because, just as with control area location, sellers are reluctant to limit their options well in advance of delivery.

856. EPSA argues in post-technical conference comments that the Commission should require the identification of neither the control area, *nor* the point of delivery, for ''into'' firm LD products. To do so would be, in EPSA's view, inconsistent with allowing firm LD contracts to qualify for network resource designation without identification of specific physical generation resources.

857. EPSA contends that, prior to the effectiveness of Order No. 890, LSEs have consistently been able to obtain network resource designations for into-Entergy firm LD contracts, thereby ensuring that the LSEs could rely on firm network transmission to deliver the energy to their specific loads when their suppliers delivered energy into the Entergy system. EPSA maintains that, beginning July 13, 2007, requests to designate into-Entergy firm LD contracts as network resources, even as daily network transmission, have been denied because LSEs have been unable to provide Entergy with the source control area and information about transmission arrangements associated with a firm transmission reservation that will be used to deliver the firm LD contract.

858. EPSA explains that LSEs cannot provide this information because, until the energy is scheduled, the LSE does not know the source control area and transmission information. EPSA maintains that, under the flexible terms of the firm LD contract, however, the seller takes full responsibility for ensuring that the energy will be delivered into the specified control area. EPSA states that source and transmission arrangement information is provided when energy is scheduled, and scheduling is made possible only because appropriate transmission arrangements have been made. If a seller cannot make the appropriate transmission arrangements to provide energy into the Entergy system, EPSA explains, it will have defaulted on its contract to deliver a firm product into Entergy. EPSA argues that, as noted in Order No. 890, the liquidated damages resulting from such a default makes the buyer whole providing the basis for the Commission's determination that firm LD contracts can be designated as network resources.

859. EPSA argues that, at a minimum, the Commission should clarify that network customers are not required to provide information as to source control area and transmission arrangements except on a day-ahead basis when such information is made available through required scheduling and tagging procedures.

860. On rehearing, Washington IOUs argue that any reliability concerns the Commission might have about lack of control area information at the time of designation is alleviated by the fact that the tagging information provided with a schedule for a designated resource contains all information to ensure reliability.

Commission Determination

861. The Commission affirms the decision in Order No. 890 to continue to require identification of the control area in which an off-system resource is located and the delivery point(s) to the transmission provider's transmission system in order to designate the resource as a network resource. Providing both the control area in which the off-system resource is located and the delivery point(s) to the transmission provider's system is usually sufficiently specific to allow a transaction to be evaluated for its effects on ATC of the local transmission system. As the Commission acknowledged in Order No. 890, however, some transmission providers might need additional information in order to determine the effects of designating off-system resources on ATC and that such transmission providers could propose variations to the *pro forma* OATT in an FPA section 205 filing.[315] We continue to believe that a generic rulemaking is not the appropriate venue to make accommodations for system-specific issues faced by transmission providers and, therefore, deny Duke's request to require more specific information regarding the transmission system from which power will originate.

862. Similarly, we decline to generically relax the designation requirements by eliminating the need to identify the source control area for an off-system resource or delivery point(s) to the transmission provider's transmission system. The Commission's policy balances the need to accurately model transactions for ATC and related purposes and the flexibility of a seller to source power from a range of generators. We are unconvinced that identification of the source control area and delivery point(s) is not needed to perform the ATC analysis in every circumstance. We therefore reject requests to allow designation of purchased power contracts that provide essentially no advance information about the location or delivery of their power sources. Waiting until the scheduling timeframe for tagging information fails to address the up-front need for information in order to accurately model ATC.

863. Several parties raise arguments relevant to local and regional concerns that merit consideration, but a generic rulemaking is not the appropriate venue to address such concerns. Transmission providers that believe that their circumstances warrant a variation from the designation requirements of the *pro forma* OATT may make a proposal under section 205 of the FPA. We have already approved one such request for Puget Sound Energy, Inc., conditioned on that company demonstrating that its tariff variation continues to be

[314] *E.g.*, Barrick Goldstrike Mines, Morgan Stanley, and Southwestern Utilities.

[315] *See* Order No. 890 at P 1481.

appropriate after the ATC standardization process is complete.[316]

864. We disagree with Financial Service Joint Intervenors' contention that there is an inconsistency between the requirement in section 29.2(v) of the *pro forma* OATT that the network customer identify the control area from which power is sourced and the finding in Order No. 890 that firm LD contracts are eligible for designation as network resources. The Commission did not state that *every* firm LD contract can be designated as a network resource, but rather that they are eligible for designation. Such contracts must also comport with the other requirements of section 29.2 of the *pro forma* OATT, including identifying the control area from which the power will originate, to actually be designated as a network resource. A seller's choice firm LD contract therefore cannot be designated until the source control area is disclosed by the seller.[317] The Commission's discussion of particular aspects of firm LD contracts does not mean that remaining requirements of section 29.2 no longer apply.

865. We decline to grant Southern's request to generically require that network customers provide as much information as they have regarding the actual, underlying generating facilities from which power will be sourced for an off-system seller's choice contract. We encourage network customers to share such information when they have it, and encourage transmission providers to develop business practices to establish procedures through which network customers can provide such information, but conclude that a formal requirement would be cumbersome to administer and enforce. We believe that the existing requirements generally provide sufficient information to evaluate a designation request.

866. Section 29.2(v) of the *pro forma* OATT requires identification of the ''delivery point(s) to the transmission provider's transmission system.'' To the extent necessary, we clarify that the term ''delivery point'' does contemplate an interface between the local transmission provider's transmission system and the neighboring transmission system from which power is being received. In response to Financial Service Joint Intervenors, we clarify that the use of the plural ''control area(s)'' in the revisions to section 29.2(v) adopted in Order No. 890 was inadvertent and amend that language accordingly in this order. We disagree that a network customer could satisfy the requirements of section 29.2(v) by identifying multiple control areas, such as all 33 control areas in the Western Interconnection, from which a particular transaction could be sourced.

867. In response to Barrick Goldstrike Mines, Morgan Stanley, and Southwestern Utilities, the Commission clarifies that the requirement in section 29.2(v) of the *pro forma* OATT to identify the transmission arrangements on external systems applies to the transmission leg from the resource being designated to the transmission provider's transmission system. If an off-system power purchase is sufficiently firm to satisfy the designation requirements, then the transmission provider need not be concerned with the upstream transmission leg(s) from the generator(s) to the point where the buyer takes title of the firm power. Because the contract itself is the resource being designated, and that contract is firm in nature, it is not necessary to demonstrate the firmness of the upstream transmission in order to designate the contract as a network resource.

(3) On-System Resources

868. In response to a commenter request, the Commission clarified in Order No. 890 that a customer may not designate as a network resource a seller's choice power purchase agreement that is sourced by generating units internal to the transmission provider's control area, since evaluating the effect on ATC would be problematic. The Commission stated that, if a customer wishes to have a choice of resources that are internal to the particular transmission provider's control area from which to dispatch power, it must designate each of the resources as network resources. The Commission did not specifically address on-system system sales (*i.e.*, purchases from a specified generation system).[318]

Requests for Rehearing and Clarification

869. Various concerns were raised in post-technical conference comments regarding a possible interpretation of Order No. 890 as prohibiting the designation of on-system system sales as network resources.[319] Some argue that such an interpretation would be inconsistent with statements in the NOPR and Order No. 890 that, when a network customer is designating a system purchase as a new network resource, the source information required in section 29.2(v) should identify that the resource is a system purchase and should identify the control area from which the power will originate.[320] Given this discussion in Order No. 890, TAPS and APPA argue that the deletion of language requiring ''description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System'' from section 29.2(v) of the *pro forma* OATT may have been inadvertent. TAPS and APPA state that they are unaware of any party having argued against the eligibility of on-system system sales for designation as network resources and that, given the absence of any indication of a problem with these types of contracts, the Commission should not implement such a policy.

870. Alabama Municipal argues in its post-technical conference comments that designation of on-system system sales as network resources does not contribute to difficulties in computing ATC. Alabama Municipal argues that system sales contracts do identify the source of power: the seller's whole generation fleet. Others argue in post-technical conference comments that, because system power is what utilities use to supply retail load, wholesale system power cannot do any more harm to ATC calculations than the utility's service to its retail customers.[321]

871. Wisconsin Electric argues that stand-alone transmission providers and RTOs should be allowed to have different rules regarding the designation of on-system system sales as network resources. Wisconsin Electric contends that within MISO, for example, deliverability studies are performed for each resource to assess whether the designated capacity is deliverable to the MISO system and that, once that deliverability test has been satisfied, another load within MISO is able to designate the same resource as a network resource. Wisconsin Electric further states that energy may not actually be delivered from a designated resource in a particular hour due to MISO decisions on which units are dispatched on an hour-by-hour basis.

[316] *See Puget Sound Energy, Inc.*, 120 FERC ¶ 61,232 (2007); *see also Arizona Public Service Company*, 121 FERC ¶ 61,246 (2007).

[317] *See* Order No. 890 at P 1481 (requiring identification of source control area, rather than more specific transmission system, prior to designation of off-system seller's choice contracts).

[318] The Commission proposed in the NOPR to maintain its current policy of allowing network customers to designate resources from system purchases not linked to a specific generating unit. *See* NOPR at P 407.

[319] *E.g.*, Alabama Municipal, Hoosier, and TAPS and APPA.

[320] *See* NOPR at P 408; Order No. 890 at P 1435.

[321] *E.g.*, Alabama Municipal, Hoosier, NRECA

872. Others argue in post-technical conference comments that prohibiting the designation of on-system system sales as network resources and requiring the designation of specific generating capacity would not be comparable to the way the transmission provider operates when serving its load.[322] Some contend that making system products more difficult to use is contrary to the Commission's policy of encouraging and facilitating use of long-term contracts and contrary to the Commission's obligations under section 217(b)(4) of the FPA.[323]

873. Many of the post-technical conference comments raise concerns regarding the burdens that would be imposed on customers if they were forced to re-structure their system purchase contracts in order to micromanage the designation of their network resources. There is general agreement that customers would be subject to unauthorized use penalties and would lose the benefits of purchases from system products if they were required to designate particular units within the seller's system.[324] In their view, requiring identification of each individual generating station with fixed amounts of generation and fixed amounts of delivery would be chaotic and overwhelming and would diminish reliability.

874. TDU Systems and TAPS and APPA argue in their post-technical conference comments that, if on-system system sales are not allowed to be designated as network resources, customers will be motivated to seek off-system system products instead, leading to pancaked transmission rates and the loss of local transmission providers as possible suppliers. TDU Systems also argue that disallowing on-system system sales to be designated as network resources would, in some areas, diminish the ability of the wholesale transmission-dependent utility systems that provide virtually the only competition in retail electricity markets before Order No. 888 to compete effectively. TAPS and APPA state that an alternative would be for the on-system seller to be the network customer and take on (or possibly avoid) the headache of designating and undesignating resources. TAPS and APPA argue that this would be practical, however, only if the network customer desires full-requirements system power and that customers seeking to use other resources in combination with the system power (as many transmission dependent utilities do) would not have this option. TAPS and APPA also point out that customers may own transmission facilities for which, under the Commission's policy, credits are to be provided only where the owner of the transmission assets is the network customer itself. TAPS and APPA therefore conclude that a transmission dependent utility may have good reason to want to be the network customer, rather than allowing the transmission provider to assume that role.

875. Great Lakes supports TAPS and APPA's position in its post-technical conference comments, adding that requiring transmission dependent utilities to be full-requirements customers of a system power seller would effectively shut out entities that do not exclusively utilize full-requirements system power contracts. Great Lakes adds that transmission dependent utilities have begun to develop the requisite expertise required to allow them to compete more effectively in the wholesale market and should not be required to give up those benefits in order to utilize system power contracts.

876. Several petitioners argue that system sales contracts are not the same as seller's choice contracts.[325] These petitioners argue that typically a seller's choice contract involves a situation where, under certain delineated circumstances, a seller that would normally sell power to the purchaser from one unit may choose to deliver power from an alternate unit. These petitioners argue that the Commission's ruling in Order No. 890 regarding the eligibility of seller's choice contracts does not affect the eligibility of system sales.

877. Duke Energy Carolinas contends in its post-technical conference comments that the requirement in section 29.2(v) to provide the delivery point for a resource sourced from purchased power could be interpreted to require either an interface delivery point or a local load delivery point. For system purchases that are sourced by generators in the same control area as the load, Duke Energy Carolinas argues, the only delivery point is the location of the load. Duke Energy Carolinas states that a network load may have more than one load delivery point, but all such points are where some network load is located. Duke Energy Carolinas also distinguishes system sales from seller's choice contracts, which it states allow the seller to select on a daily basis the source of the physical power. Duke Energy Carolinas contends that system sales do not fit within this category of seller's choice contracts since the source control area is known and there is no ''choice'' as to which units will be used to serve a network customer's load, given that units are dispatched according to economic and reliability dispatch principles.

878. Duke Energy Carolinas also argues that disallowing on-system system sales would be inconsistent with the Commission's longstanding practice of accepting network integration transmission service agreements with designated network resources such as ''Seller's Generation System'' or ''Contract with Seller'' with no concern about transmission providers calculating ATC. Duke Energy Carolinas further argues that disallowing on-system system sales would be inconsistent with allowing at least some wholesale customers to be classified as native load customers and permitting the seller to serve such native load customers from a choice of all of its network resources. If the Commission does not allow on-system system sales to be designated as network resources, Duke Energy Carolinas requests clarification of whether a wholesale customer that entered into an on-system system purchase contract with a transmission provider prior to July 13, 2007 can continue to designate the contract as a network resource. Duke Energy Carolinas also requests various other clarifications regarding the designation of system sales as network resources.

879. TAPS and APPA state that, while the *pro forma* OATT does not now appear to require it, they would not object to a requirement that every network customer, as well as the transmission providers and merchant affiliates, seeking to designate on-system system sales (or generation fleet) list the generators in the portfolio that stands behind it, provided that this not

[322] *E.g.*, Alabama Municipal, Hoosier, TDU Systems, and TAPS and APPA.

[323] *E.g.*, Great Lakes, Hoosier, TDU Systems, and TAPS and APPA.

[324] *E.g.*, Alabama Municipal, Duke, Great Lakes, Hoosier, Kansas Power Pool, NRECA, PNGC Power, TAPS and APPA, TDU Systems, and Wisconsin Electric. PPL Parties also appear to support allowing on-system system sales to be designated as network resources. PPL Parties state that they support allowing designation of on-system ''seller's choice'' contracts, but their comments about increased reliability and reduced costs when service is provided by a ''fleet of generators'' suggest they are specifically in support of allowing designation of on-system system sales, and not necessarily on-system seller's choice contracts. Southern also argues that system sales should be allowed to be designated so long as the underlying generating facilities are individually capable of receiving firm transmission service during the period of designation.

[325] *E.g.*, NRECA, TDU Systems and Wisconsin Electric. Duke Energy Carolinas and Hoosier make similar arguments in their post-technical conference comments.

translate to a requirement to assign particular generators or amounts to serve the contract. These petitioners argue that the location of the generators, which presumably the transmission provider knows anyway, ought to be enough to permit the transmission provider to determine whether the system sale can be delivered to the customer and, thus, whether the designation of the network resource can be accepted.

880. Bonneville argues that, because of the interconnected nature of a hydroelectric power system, it cannot make power sales from particular generating units and, therefore, all of its sales are system sales. Bonneville states that the federal hydroelectric projects in the Pacific Northwest are multi-purpose projects and that the operators (the United States Corps of Engineers and Bureau of Reclamation) cannot dedicate a given hydroelectric project to generate a given amount of power every hour to serve a given contract or for any other purpose. Bonneville states that almost 100 of its customers take network transmission service and have included Bonneville system purchases of power as network resources. Bonneville also notes that, under the Northwest Power Act, it is obligated to sell electric power to each Northwest utility to meet the firm power load, to the extent that the utility's firm power load exceeds its resources.[326] Bonneville maintains that nothing in the Northwest Power Act contemplates sales out of, or rates based on, individual resources, and that all of Congress's directives treat federal generation as a whole and make no distinction based on the individual resource. Bonneville argues that it has addressed the ATC issues that the Commission has identified through its AFC methodology. PNGC Power and PPC express support in their post-technical conference comments for Bonneville's general position with respect to the designation of on-system system sales from the Bonneville's hydroelectric system.

881. Several of the post-technical conference comments address the eligibility of on-system seller's choice contracts to be designated as network resources. Southern states that it generally opposes allowing on-system seller's choice contracts to be designated on a long-term basis, but acknowledges that such contracts might be designated on a short-term basis. Southern states that many seller's choice contracts require the source to be named at least on a day-ahead basis. Southern states that it would be acceptable to designate such resources on a short-term basis once the delivery source is identified.

882. Kansas Power Pool, however, argues, in its post-technical conference comments, that all seller's choice contracts should be eligible to serve as network resources. Kansas Power Pool argues that it is the supplier, not the customer, of a seller's choice contract that enjoys the flexibility to select resources or to determine which resources will or will not be dispatched.

883. Some post technical conference comments argue that seller's choice contracts from on-system generation located in an unconstrained system or zone (*i.e.*, an area within which there are no internal paths for which ATC is calculated) should be eligible for network resource status.[327] Conversely, Duke Energy Carolinas and EEI argue that, if a system or zone has congestion (*i.e.*, internal ATC paths), then unit designation becomes necessary to be able to correctly calculate ATC. South Carolina E&G argues that unconstrained transmission systems could become constrained over time, but any possible need for the designation of network resources to assist in calculating internal ATC will be observable on OASIS. South Carolina E&G argues that a transmission provider has no incentive to overstate ATC, so the Commission can be assured that designation of network resources is unnecessary if OASIS shows no constraints, and vice versa.

884. Other post technical-conference comments oppose the proposal for unconstrained transmission areas, at least as applied to on-system system sales, arguing that the proposal appears to be motivated by the incorrect assumption that the Commission in Order No. 890 found that both on-system seller's choice contracts and on-system system sales are eligible for designation as network resources.[328] With regard to seller's choice contracts, Hoosier and TDU Systems argue that adopting an unconstrained transmission area approach would leave those LSEs unfortunate enough to be located on constrained systems without the transmission rights they had prior to Order No. 890. Hoosier and TDU Systems argue that ATC would not be limited unless the transmission provider has failed to expand its system to meet the needs of its network customers, pointing to TLR statistics to emphasize concerns regarding particular transmission providers. Hoosier contends that restricting seller's choice contracts to particular areas of the transmission provider's system would assume the existence of constraints on a system to such a degree that the long-held rights of network customers to designate their historical resources as network resources would be eliminated. Hoosier and TDU Systems believe that the Commission's policy should assume transmission providers have been planning and expanding their systems appropriately, putting the burden on the transmission provider whose system is so constrained that it cannot evaluate internal ATC to make a filing proposing changes to its OATT to accommodate their problems. Acceptance of the unconstrained transmission area proposal, they argue, would be inconsistent with the Commission's obligations under FPA sections 217. Hoosier and TDU Systems argue that the transmission provider should experience no more difficulty in calculating ATC for its network customers than it does to serve its own retail native load.

Commission Determination

885. In the NOPR, the Commission proposed to continue to allow resources from system purchases not linked to a specific generating unit to be designated as network resources.[329] The Commission did not specifically address on-system system sales in Order No. 890, focusing instead on on-system seller's choice contracts.[330] Thus, the Commission's existing policies regarding the eligibility of on-system system sales for network resource status were not affected by the reforms adopted in Order No. 890.

886. Various concerns have nonetheless been expressed regarding the treatment of on-system system sales in requests for rehearing and clarification and at the technical conference held by Commission staff on July 30, 2007 and in subsequent comments. TAPS and APPA, for example, question whether the revisions to section 29.2(v) of the *pro forma* OATT adopted in Order No. 890 were intended to alter the designation requirements for on-system system sales. Alabama Municipal and Wisconsin Electric argue that the Commission's concerns regarding the accuracy of ATC calculations are not relevant in the context of system sales. In order to respond to these concerns, and provide guidance to the industry, we clarify that Order No. 890 was not intended to change the requirements for

[326] 16 U.S.C. 839a(10).

[327] *E.g.*, Duke Energy Carolinas, EEI, Pacific Northwest IOUs, South Carolina E&G, and Southwestern Utilities.

[328] *E.g.*, TAPS and APPA.

[329] *See* NOPR at P 407.

[330] *See* Order No. 890 at P 1483.

designating on-system system sales as network resources under the *pro forma* OATT.[331]

887. Prior to Order No. 890, section 29.2(v) of the *pro forma* OATT did not distinguish between the designation of on-system and off-system resources. In order to designate a network resource, the network customer was required to provide information regarding the unit size, the amount of capacity being designated, VAR capability, operating restrictions, approximate variable cost, and arrangements governing the third-party sales and deliveries. For off-system power purchases, information was also required regarding the source of supply, control area location, transmission arrangements, and delivery point(s) to the transmission provider's system. These various requirements were stated in a single series of bullets in section 29.2(v).

888. In Order No. 890, the Commission restructured section 29.2(v) to more clearly identify the information that must be provided for on-system resources and off-system resources, breaking apart the series of bullets into two separate lists. The basic requirements of designation remain the same, except that the tariff language more clearly specifies the information (*i.e.*, source of supply, control area location, transmission arrangements, and delivery point(s) to the system) that applies only to off-system resources. This was implicit in the prior tariff formulation, since the underlying information related to off-system transactions. The Commission sought to more explicitly state the information required under section 29.2(v) to facilitate compliance with the new obligation for customers to provide an attestation that the requirements for designation as a network resource have been met for the particular resource being designated.

889. These changes to the *pro forma* OATT therefore did not change the substantive requirements for designating network resources as they apply to on-system and off-system resources. For on-system resources, network customers must continue to provide the same information in their designation request: the unit size, the amount of capacity being designated, VAR capability, operating restrictions, approximate variable cost, and arrangements governing the third party sales and deliveries. We understand that it is common practice in the industry for transmission providers to consider the identification of the source system for an on-system system sale sufficient to provide this information, since the transmission provider already has the necessary information for constituent generators on the system given that the units supporting the system sale have otherwise been designated for use by network or native load.[332] Nothing in Order No. 890 imposed new information requirements on transmission providers that previously deemed the requirements of section 29.2(v) fulfilled by the identification of the source system for an on-system system sale. Network customers may therefore continue to designate such resources as appropriate.

890. To the extent there are concerns regarding the effect of designating on-system system sales on ATC, we note that transmission providers have been directed to address the effect on ATC of designating and undesignating network resources as part of the on-going NERC/NAESB standardization effort.[333] Through that process, transmission providers will develop consistent methodologies for calculating the effect on ATC of designation resources, both on-system and off-system. Until the standardization process is complete, however, the Commission cannot know whether additional information is required in order to accurately model the designation of an on-system system sale. We will revisit the requirements of section 29.2(v) as necessary after the NERC/NAESB ATC standardization effort is complete. Until such time as those requirements change, transmission providers should continue their existing practices regarding the designation of on-system system sales as network resources. Further clarification as requested by Duke is not necessary.

891. The Commission affirms the finding in Order No. 890 that on-system seller's choice contracts generally do not provide enough information to satisfy the requirements for designation as a network resource. For on-system resources, the location of the capacity is necessary for determining the effect of a proposed designation on transmission capacity, both for evaluating the acceptability of the resource itself, and for allowing future transmission service requests to be evaluated. We agree with Southern, however, that a contract that may not provide enough information provided to be designated as a network resource at one time may become eligible for designation as the information becomes available. For instance, if a day before scheduling the seller were to identify source generation for a seller's choice contract for the following day, and if the contract were to bind the seller to use the newly identified generation (at least for the period that it was identified), then the resource would be eligible to be designated for the period during which the source information is firm (provided the resource complied with all other relevant requirements). At that point, the agreement is effectively no longer a seller's choice contract for the specified period. If, on the other hand, the seller identifies only what it *intends* to source the power with, but no contractual mechanism prevents the seller from sourcing the power from an alternative source prior to scheduling, then the resource would remain a seller's choice contract and would not be eligible for network resource status.

892. We disagree with Kansas Power Pool's argument that, because it is not the customer that has the flexibility to select the generation in a seller's choice contract, such contracts should be eligible for network resource status. It is the inability to evaluate or determine the proper transmission reservations for on-system seller's choice contracts that is concerning, and not the fact that it is the seller or the buyer who has the ''choice'' of how to dispatch the power.

893. With regard to the proposal to allow the designation of on-system seller's choice contracts within unconstrained transmission areas, we believe that our clarification above that Order No. 890 did not change the Order No. 888 requirements for designating on-system system sales will alleviate most of the concerns expressed by supporters of this proposal.

(4) Resource Information

894. In Order No. 890, the Commission affirmed the requirement that customers designating a network resource must provide a description of the resource (current and 10-year projection) including, among other things, approximate variable generating cost ($/MWH) for redispatch computations and any operating restrictions.

Requests for Clarification and/or Rehearing

895. EEI requests clarification that the operating restrictions information required by section 29.2(v) of the *pro forma* OATT need not be provided for

[331] Slice-of-system sales are a type of system sale and, therefore, our discussion below regarding on-system system sales applies equally to on-system slice-of-system sales, as well as system sales from hydroelectric systems.

[332] It may be the case that identification of another system within the transmission provider's control area, such as a fleet of merchant generators, would trigger the need for additional information under section 29.2(v). That type of transaction, however, does not appear to be of concern to petitioners and thus we do not address it here.

[333] *See* Order No. 693 at P 1041.

off-system system sales if that information is not contained in the relevant contracts. EEI also suggests that the variable price of energy specified in the contract and not the actual variable costs of the units that supply the sale serve as the variable generating cost for redispatch computations. EEI argues that the network customer generally will not know the actual variable cost and that the price specified in the contract is the relevant price for purposes of redispatch, since that is the cost that the network customer will incur or avoid if its contract is redispatched up or down. Bonneville and Duke Energy Carolinas question in their post-technical conference comments what variable costs should be provided for on-system system sales. Duke Energy Carolinas states that the contract energy price is used as the approximate variable generating cost for redispatch purposes.

896. EPSA requests clarification that network customers are not required to provide a redispatch cost for a firm LD contract, since such contracts are effectively take-or-pay contracts and cannot, for example, provide a source of incremental energy if Entergy is surveying redispatch options to address a reliability event. EPSA argues that the fact that not all network resources are suitable for redispatch options is not unusual, since many units may be must-run in order to meet reliability needs (such as voltage support) or contractual requirements (such as QF purchases), or to reflect operating characteristics (such as nuclear units that cannot be cycled off and on quickly). EPSA is concerned that some transmission providers may believe that the supplier of a firm LD contract is required to provide the network customer with a contract-specific variable redispatch cost based on its own supply alternatives which, as noted, is not possible. EPSA argues that a determination that designation requests could be rejected for lack of information that is not relevant to such contracts would be contrary to the Commission determination that firm LD contracts can serve as network resources.

Commission Determination

897. The Commission clarifies in response to EEI that the operating restrictions applicable to off-system system sales designated as network resources are the restrictions set forth in the relevant contracts, not the underlying units supplying the contracts. Similarly, the approximate generating cost for redispatch purposes for a system sale is the variable energy cost specified in the contract.

898. We disagree with EPSA that a network customer should not be required to provide a redispatch cost for a firm LD contract. When a network customer designates a network resource, it agrees under section 30.5 of the *pro forma* OATT to redispatch its resource as requested by the transmission provider pursuant to section 33.2 of the *pro forma* OATT. A firm LD contract is like any other resource, redispatchable by the transmission provider within the customer's rights to the resource, as stated in the contract.

(5) General

899. In Order No. 890, the Commission determined that firm point-to-point service provided on a conditional firm basis is sufficiently firm to be used for transmission to import an off-system designated network resource. The Commission also denied a request to require the validity of network resource designations to be verified by the seller or owner of the generation, finding that such a verification is unnecessary in light of the new attestation requirements. Finally, the Commission clarified that the minimum term for designations of new network resources should be the same as the minimum term used for firm point-to-point service (*i.e.*, daily), unless otherwise demonstrated by the transmission provider and approved by the Commission.

Requests for Rehearing and Clarification

900. Duke seeks clarification that network customers that designate off-system resources supported by conditional firm point-to-point transmission service are required to have in place or obtain from the transmission provider reserves or backup resources to cover the periods when the conditional firm point-to-point transmission service is not available.

901. Indicated Commenters argue that a network customer designating a generating unit that it does not own should have an obligation to provide contemporaneous notice of the designation to the owner of the generating unit. Indicated Commenters argue that such notice should indicate, at a minimum, the amount of capacity claimed to be under contract and the duration of the claimed contractual right. Indicated Commenters argue that their proposed notice requirement is appropriate since designation as a network resource may subject the generation owner to certain must-offer requirements (in organized markets) or redispatch orders (in non-organized markets). Indicated Commenters also contend that such a notice requirement would facilitate enforcement of the OATT requirements by ensuring that generators are not obligated without their knowledge and that false or questionable designations are identified promptly. Indicated Commenters argue that the current system of audits and increased penalty authority and other sanctions will have some deterrent effect, but that it will do nothing to make generation owners and other users of the transmission system whole after violations occur.

902. Pacific Northwest Parties, joined by PPC in its post-technical conference comments, requests clarification that, to the extent a transmission provider establishes a minimum term for designation of network resources, it need not be the same as the minimum term offered by the transmission provider for firm point-to-point service. Pacific Northwest Parties argue that this clarification will promote hourly firm energy markets by allowing transmission providers to offer hourly firm point-to-point transmission service even if they cannot accommodate a one-hour minimum term for designation of network resources.

903. Reliant asks in its post-technical conference comments that the Commission carefully consider any variations from the network service requirements of the *pro forma* OATT proposed by RTOs and ISOs in their compliance filings. Reliant contends that requirement for proper identification of network resources is intended to ensure that transmission reserved for firm network use is used only to deliver properly designated network resources and that no more than one LSE has identified the same resource capacity as serving its load (*i.e.*, to avoid double-counting). Reliant asks the Commission to ensure that any variations from the *pro forma* OATT proposed by RTOs and ISOs similarly prevent double-counting.

Commission Determination

904. The Commission declines Duke's request to require that a network customer, as a condition of designating off-system resources supported with conditional firm point-to-point transmission service, have in place or obtain from the transmission provider reserves or backup resources to cover the periods when the resource supported with conditional firm point-to-point transmission service might not be delivered. Duke appears to misunderstand the nature of conditional firm service. A network customer utilizing conditional firm service would be using firm transmission service

except during the limited periods where such service is conditional. Transmission service for those resources could be curtailed during such periods, similar to how secondary network service may be curtailed prior to curtailment of other firm transactions. In the event conditional firm service is curtailed, the network customer would be required to serve its network load from other resources, just as when the transmission provider curtails the network customer's use of secondary network service. It is not the responsibility of the transmission provider to ensure that the network customer has sufficient resources to meet its load.

905. We disagree with Indicated Commenters that network customers should be required to serve notice on sellers of power that is designated as a network resource. The obligation to comply with the designation requirements applies to the network customer, not the resource owner. The appropriate place to impose obligations on the resource owner is in the contract governing the sale. To the extent a contract has been executed that meets the requirements for network resource designation, it is not clear why the seller would be affected by the actual designation of the resource, since the network resource redispatch obligations do not go beyond the amount of power that is available under the contract as designated by the network customer. If, as Indicated Commenters argue, there are unique considerations in some organized markets, a generic rulemaking is not the appropriate venue to make accommodations for such system-specific issues.

906. We also decline to grant the request of Pacific Northwest Parties to generically allow transmission providers to establish a minimum term for designations of network resources that is not the same as the term for firm point-to-point service. Pacific Northwest Parties do not explain why a transmission provider could accommodate hourly point-to-point transmission service, but not hourly network service. To the extent that a transmission provider has specific circumstances that justify adoption of a different minimum term for network resource designations, it should raise them in the context of an FPA section 205 filing.

907. To the extent Reliant or any other party has a concern regarding an RTO or ISO's compliance with the requirements of Order No. 890, the appropriate forum to consider those concerns is on review of the underlying compliance filing.

b. Documentation for Network Resources

908. The Commission concluded in Order No. 890 that transmission providers should be responsible for verifying that third-party transmission arrangements to deliver an off-system designated network resource to the transmission provider's system are firm. However, the Commission found that transmission providers should not be responsible for verifying that the generating units and power purchase agreements designated as network resources satisfy the requirements of section 30.1 and 30.7 of the *pro forma* OATT. The Commission instead required network customers and the transmission provider's network function to include a statement with each application for network service or to designate a new network resource that attests, for each network resource identified, that (1) the transmission customer owns or has committed to purchase the designated network resource and (2) the designated network resource comports with the requirements for designated network resources.

909. The Commission stated that network customers should include this attestation in the customer's comments section of the request when it confirms the request on OASIS. In the event that a transmission provider or any other network customer designates a network resource that it does not own or has not committed to purchase, or that does not comport with the requirements for designated network resources, the Commission will deem the network customer to be in violation of the *pro forma* OATT and will consider assessing civil penalties on a case-by-case basis, consistent with the Commission's Policy Statement on Enforcement. The Commission rejected requests to allow transmission providers to voluntarily verify terms and conditions of power purchase agreements, concluding that such authority is unnecessary in light of the new attestation requirement.

Requests for Rehearing and Clarification

910. South Carolina E&G asks for clarification of the language describing the attestation requirement in paragraph 1521 of Order No. 890, arguing that it is a less precise paraphrase of the language in section 30.2 of the *pro forma* OATT. South Carolina E&G asks the Commission to confirm that the precise language of section 30.2 governs and that paragraph 1521 of Order No. 890 does not add any additional requirements. South Carolina E&G also suggests that, because of space limitations in the customer's comment section on OASIS, the attestation can be made by a reference, such as ''the customer attests pursuant to Section 30.2.''

911. Several petitioners request rehearing of the Commission's decision to not allow transmission providers to review power supply contracts for power purchases designated as network resources.[334] These petitioners argue that allowing such review would improve reliability and/or allow transmission providers to more accurately model their systems. Duke and EEI argue that transmission providers should have the right, but not the obligation, to review such contracts. They assert that transmission providers have a legitimate interest in ensuring the reliability of energy service to network loads on their systems, since interruptions and resulting imbalances may harm the reliability of the entire system, and because the transmission providers may be forced to provide backup energy in order to avoid curtailment of network load. EEI complains that network customers who incorrectly designate unqualified resources take transmission capacity that otherwise would be used for transmission service from legitimate network resources. Duke notes that it has routinely been provided access upon request to underlying contracts, with commercially sensitive information redacted.

912. EEI argues that reliance on attestations by network customers that their power purchases qualify as network resources is insufficient to adequately protect against improper designations. EEI states that some of its transmission provider members have found, by comparing customer contracts against network resource certifications that are required by their business practices, that some customers are incorrectly designating power purchase contracts that clearly do not meet the Commission's criteria. EEI argues that after-the-fact audits of customers' attestations do not address the system reliability concerns of the misuse of the transmission system that results from the designation of unqualified network resources.

913. EEI acknowledges the Commission's reluctance to place transmission providers in the position of policing whether customers' contracts qualify as network resources, but argues that does not warrant precluding voluntary review of network customers' purchased power contracts. EEI

[334] *E.g.,* Duke, EEI, and MISO.

contends that the Standards of Conduct prohibit any transfer of customer information to the transmission provider's marketing and energy affiliates and that any residual concerns about transmission providers deciding whether power purchase contracts qualify as network resources could be addressed by permitting the transmission provider to act in a purely advisory role. EEI suggests that transmission providers could bring concerns about possibly incorrect attestations to the attention of the customer or, if necessary, the Commission's Enforcement Hotline. EEI argues that allowing such review by the transmission provider would not supplant the obligation of the network customer to attest to the validity of its designations of network resources.

914. MISO argues that a statement that the transmission customer owns or has committed to purchase the designated network resource and that the designated network resource comports with applicable requirements does not provide the necessary level of assurance to the transmission provider, particularly in those cases where the network customer unduly relies on representations made by its supplying marketers. MISO asks the Commission to supplement its existing attestation requirements with a certification from an external control area's administrator and/or the seller of the generation that the resource being designated in that area is not counted as a designated network resource for another load on or off the system.

915. Joined by Southern, EEI also objects to making transmission providers responsible for verifying the firmness of off-system transmission service. Southern argues that the requirement that transmission providers verify the firmness of off-system transmission service is unduly burdensome and could result in unnecessary rejection of requests to designate network resources on a day-ahead basis. Southern contends that the specific transmission path(s) and arrangements to deliver power to the network customer usually have not been finalized at the time off-system resources are designated in the ''day-ahead'' cycle and, instead, are typically finalized the hour before delivery. Southern and EEI suggest that sections 29.2(viii), 30.1, 30.2, and 30.7 of the *pro forma* OATT be amended to allow the network customer to attest that the external resource is contractually required to be delivered using firm transmission service, without confirmation that an actual firm path has been scheduled and confirmed. Southern argues that transmission customers also could be required to attest to the firmness of their requested and expected transmission service and face the possibility of complaint, audit or other inquiry and, ultimately, sanction for false attestations.

916. In the alternative, EEI requests further clarification that transmission providers could obtain waiver of the verification requirement if they demonstrate that verification of the firmness of transmission service is not required because of the way in which transmission service and markets operate on the transmission provider's transmission system. EEI states that network resources in the West are frequently designated at hubs such as the Palo Verde Hub prior to tagging. EEI states that a network customer has very limited ability to know the source of the energy that is being made available at a specific hub and, indeed, has no need to know that information since what is important is the seller's commitment that the energy is being provided at that hub on a firm basis. EEI argues that the host transmission provider has no ability or need to evaluate the firmness of the external transmission path between the generator and hub. EEI contends that the Commission's decision to require verification of the firmness of transmission paths, in conjunction with other requirements relating to off-system network resources, has caused financial institutions to consider withdrawing from the market.

917. EEI and Southern also argue that, in many instances, transmission providers are unable to perform the verifications required by the Commission. They state that some systems refuse to allow other transmission providers access to their OASIS and refuse to perform the verification themselves. EEI suggests that the Commission require each transmission provider to grant ''read only'' access to its OASIS by any computer that has an X509 security certificate (the security certificate that is provided to transmission function personnel). EEI requests that the Commission, at a minimum, delay the date by which transmission providers must verify off-system transmission service for 180 days, in order to allow time for modifications to OASIS protocols to grant access to transmission providers who are seeking to verify the firmness of transmission service.

918. If the Commission declines to amend the attestation requirement, EEI requests clarification with regard to instances where transmission providers cannot verify the firmness of off-system transmission service because the information is not posted on OASIS. EEI states that many non-jurisdictional transmission providers that do not have reciprocity tariffs also do not have OASIS nodes on which the firmness of service can be verified. EEI also states that grandfathered transmission agreements frequently are not posted on OASIS or, if they are posted, postings do not contain sufficient detail to enable off-system transmission personnel to verify the firmness of the transmission service.

Commission Determination

919. The Commission clarifies, in response to South Carolina E&G's request, that the language in paragraph 1521 of Order No. 890 is only meant to be a paraphrase of the more detailed attestation to be provided in the *pro forma* OATT itself. A network customer designating network resources should submit an attestation using the language set forth in sections 29.2(viii) and 30.2 of the *pro forma* OATT, as amended in Order No. 890, not the language of the preamble. A network customer is not permitted to merely reference the applicable section of the *pro forma* OATT when completing the attestation requirement. If the OASIS customer comment section does not currently allow enough space for a network customer to provide its attestation, transmission providers should modify, in coordination with NAESB, OASIS functionality to accommodate the full attestation. In the interim, the transmission provider should identify alternate means, such as by telefax or e-mail, for the network customer to provide the attestation.

920. We decline to require that network customers provide their power supply contracts to transmission providers for review, whether such review is advisory or otherwise. Allowing transmission providers to review power sales contracts would put transmission providers in the position of interpreting their network customer's contracts and accepting or rejecting designations based on their interpretations. Regardless of the protections provided by the Standards of Conduct, it would be inappropriate for transmission providers to be in that position. The new attestation requirement properly places the responsibility of interpreting the terms of a power sales agreement on the network customer, an actual party to the agreement. We believe that the new attestation requirement, coupled with the prospect of significant civil penalties for improper attestations, will prove effective at providing the proper

incentives for network customers to not designate ineligible network resources.

921. Similarly, we decline to require, as requested by MISO, that network customers designating off-system resources provide a certification from the external control area's administrator and/or the seller of the generation that the resource being designated is not counted as a network resource for another load. Again, it is the responsibility of the network customer to assure that the requirements of the *pro forma* OATT are satisfied prior to requesting the designation of a network resource. The network customer must take appropriate steps to ensure that the resource has not been committed for sale to non-designated third party load or is otherwise unable to be called upon to meet the network customer's network load on a non-interruptible basis.

922. We affirm the decision in Order No. 890 to require each transmission provider to verify the firmness of off-system transmission service to deliver designated network resources to the transmission provider's system. Under normal circumstances, this verification requirement should not present a significant burden for the transmission provider because it only requires review of the transmission arrangements from the designated network resource to the transmission provider's system. Several of the arguments raised by petitioners incorrectly assume that the transmission provider is under an obligation to look beyond a power purchase designated as a network resource to upstream transmission arrangements from the source generator. There is no need for the transmission provider to consider transmission arrangements upstream of the designated resource, since the network customer has attested that the resource is sufficiently firm to be designated as a network resource. We therefore do not believe, as Southern argues, that the verification process will result in unnecessary rejections of request to designate network resources.

923. We recognize that, in some circumstances, the external transmission provider may not have an OASIS or make relevant information on its OASIS available to other transmission providers and, therefore, the host transmission provider may be unable to use OASIS to verify the firmness of transmission used to deliver the off-system designated network resource. The Commission explained in Order No. 890 that the transmission provider should attempt to remedy such information deficiencies through informal communications with the customer.[335] Network customers have every incentive to cooperate in providing this information since, if the transmission provider is unable to confirm the firmness of these transmission arrangements, the request to designate the network resource is deficient. We agree with EEI and Southern, however, that transmission providers should have access to view other transmission providers' OASIS for this purpose. We therefore direct transmission providers to allow such access and to work through NAESB to modify business practices as necessary.[336] We decline to waive the verification requirement in the interim since transmission providers are able to request this information directly from customers.

c. Undesignation of Network Resources

(1) Risk to ATC Rights

924. The Commission clarified in Order No. 890 that a request for termination of a network resource that is concurrently paired with a request to redesignate that resource at a specific point in time will not result in the network customer permanently forfeiting its rights to use that resource as a designated network resource. Any change in ATC that is determined by the transmission provider to have resulted from the temporary termination shall be posted on OASIS during this temporary period. A request that is not accompanied with a request to redesignate that resource at a specific point in time is to be considered an indefinite termination. After an indefinite termination of a resource, the network customer has no continuing rights to the use of such resource and future requests to designate that resource would be processed consistent with section 30.2 of the *pro forma* OATT as a designation of a new network resource.

Requests for Clarification and Rehearing

925. NorthWestern argues that, once upgrades specified through the interconnection process have been installed, the generator can be specified as a network resource by any customer, at the time of commercial operation of the generator or at any time in the future. NorthWestern acknowledges that the Commission rejected this position in Order No. 890, but contends that the Commission's determination cannot be reconciled with the ability of a generator under Order No. 2003 to designate, during the application process, whether it wishes to be studied and interconnected as a network resource or an energy resource.[337] NorthWestern contends that interconnection as a network resource assumes that the generator will be eligible to be designated by any network customer to serve its load in the future. If this is not the case, NorthWestern questions the distinction between energy resource interconnection service and network resource interconnection service and the transmission provider's ability to confidently study any network generation request will be diminished. NorthWestern states that a generator's request for network interconnection does not necessarily mean that any customer has designated the generator as a network resource, but only that it may be designated as a network resource by any customer.

926. NorthWestern also requests clarification regarding the interaction of transmission service and generation interconnection requests, asking the Commission to confirm that both should be studied through a single queue prioritized by request date. NorthWestern argues that decoupling the network generation interconnection study from the transmission service study could undermine reliability. NorthWestern suggests that all generation interconnection and transmission service requests be studied through a single study queue, where the requests are prioritized by their request date, in order to allow the relationship and mitigation requirements between senior and junior queued transmission and interconnection requests to be known and applied appropriately in junior queue studies.

Commission Determination

927. We disagree with NorthWestern that a generator interconnected under network resource interconnection service (NRIS) may be designated as a network resource by any customer at any point in time. As the Commission explained in Order No. 2003–A, NRIS status does not convey any right to transmit power and does not constitute a reservation of transmission capacity to any specific point.[338] The purpose of NRIS is to provide only those network upgrades needed to allow the aggregate of generation in the facility's local area to be delivered to the aggregate of load on the transmission provider's

[335] *See* Order No. 890 at P 1527.

[336] Transmission providers are free to use the NAESB standards development process to create automated OASIS functionality for verifying third-party transmission service at the time a designation request is submitted or any other processes to further minimize any burden associated with the verification requirement.

[337] *Citing* Order No. 2003.

[338] Order No. 2003–A at P 516.

transmission system, such that the output of the generating facility will not be ''bottled up'' during peak load conditions.[339] As a result, NRIS does not necessarily provide the interconnection customer with the capability to physically deliver the output of its generating facility to any particular load on the system without incurring congestion costs. Requests for delivery service inside the transmission provider's transmission system may require additional studies and upgrades to reduce congestion to acceptable levels.[340]

928. We decline to adopt at this time NorthWestern's request that all transmission service and generation interconnection requests be studied through a single queue prioritized by application date and time. NorthWestern requests specific revisions to the management of generator interconnection and transmission service request queues that were not proposed in the NOPR and are beyond the scope of this proceeding. Earlier this month, Commission staff held a technical conference to address issues related to the management of interconnection queues in Docket No. AD08–2–000.[341] The queuing concerns raised by NorthWestern are more appropriately addressed in that proceeding.

(2) Minimum Lead-Time

929. The Commission concluded in Order No. 890 that network customers should not be permitted to make firm third-party sales from any designated network resource without (1) undesignating that resource for the period of the third-party sale pursuant to section 30.3 of the *pro forma* OATT and (2) providing notice of such undesignation before the firm scheduling deadline. The Commission stated that this requirement allows undesignated capacity to be acquired on a non-firm basis without creating an undue adverse effect on third-party sales.

Requests for Clarification and Rehearing

930. Various petitioners have requested rehearing or clarification of the Commission's determinations regarding the minimum lead-time for undesignating network resources in order to make firm third-party sales.[342] Petitioners generally object to imposing this minimum lead-time requirement, arguing that it unduly restricts the ability of network customers and the transmission provider to engage in third-party sales and impairs liquidity in the market.

Commission Determination

931. In a notice issued on September 7, 2007, the Commission extended the effective date of the minimum lead-time for undesignating network resources adopted in Order No. 890, deferring the effectiveness of the phrase ''* * * but not later than the firm scheduling deadline for the period of termination'' in section 30.3 of the *pro forma* OATT.[343] The Commission stated that it will address the appropriate effective date for that tariff language, or any modification thereto, in a future order to be issued in this proceeding. The Commission therefore defers responding to the requests for rehearing and clarification on this subject pending further action in the forthcoming order.

(3) General

932. In response to commenter requests, the Commission addressed a number of other issues in Order No. 890 related to the undesignation of network resources. Among other things, the Commission denied a request that network customers be given the flexibility to substitute new designated network resources without abandoning the original transmission queue position of the existing designated network resource. The Commission explained that granting the request would, without any apparent justification, put point-to-point customers seeking ATC freed up by an undesignation at a disadvantage. Pending the implementation of new OASIS functionality to accept electronic requests to designate and undesignated network resources, the Commission stated that network customers could submit their requests by transmitting the required information to the transmission provider by telefax or providing the information by telephone over the transmission provider's time recorded telephone line.

933. The Commission clarified that a network customer may only enter into a third-party power sale from a designated network resource if the third-party power purchase agreement allows the seller to interrupt power sales to the third party in order to serve the designated network load. The Commission stated that such interruptions must be permitted without penalty, to avoid imposing financial incentives that compete with the network resource's obligation to serve its network load. The Commission also clarified that firm third-party sales may be made from an undesignated portion of a network customer's network resources (*i.e.*, a ''slice-of-system sale''), so long as all of the applicable requirements are met. The Commission stated that the network customer must submit undesignations for each portion of the resource supporting the third-party sale.

934. The Commission rejected requests to relax rules for changing the undesignation of network resources at any time to handle system emergencies, force majeure events, forced outages or unusual weather conditions. The Commission explained that other procedures such as those in NERC's standard for Capacity & Energy Emergencies, EOP–002–2, or the possible use of capacity benefit margin are more appropriate to deal with legitimate system emergencies. In situations where a request to undesignate a network resource cannot be accommodated without jeopardizing reliability, the Commission stated that the transmission provider could deny the request.

Requests for Rehearing and Clarification

935. Bonneville argues that, if the only ATC on a path is the ATC freed up by an undesignation, then the network customer should be granted use of that ATC for its requested alternate service. Bonneville contends that such a policy would not adversely affect customers because, if the customer that is undesignating a resource is not placed first in line for the capacity made available by the undesignation, that customer would not undesignate (since it will continue to need the capacity on its existing path) and no capacity would be freed up for others. Bonneville concludes that refusing to place the undesignating customer first in line for the freed-up ATC will harm that customer while advantaging no one. Bonneville suggests that allowing such redirects of network resources would be particularly helpful for intermittent resources such as wind, given that transmission customers with state-

[339] *Id.* at P 531.

[340] *Id.* at P 502.

[341] *See Interconnection Queuing Practices,* Notice of Technical Conference, Docket No. AD08–2–000 (Nov. 2, 2007); *Interconnection Queuing Practices,* Notice Inviting Comments, Docket Nos. AD08–2–000, *et al.*

[342] *E.g.,* APS and EEI, E.ON U.S., Financial Service Joint Filers, Pacific Northwest Parties, PNM, Progress Energy, Washington IOUs, and WSPP. In addition, APS and EEI, Barrick Goldstrike Mines, Bonneville, EPSA, Morgan Stanley, Pacific Northwest IOUs, PNGC Power, Powerex, PPL Parties, Public Power Council, San Diego G&E, SCE&G, SoCal Edison, Southern, Southwestern Utilities, and WSPP filed post-technical conference comments on this issue.

[343] *Preventing Undue Discrimination and Preference in Transmission Service, Notice Granting Extension of Effective Date,* 120 FERC ¶ 61,222 (2007).

mandated renewable resource requirements may wish to redirect for a short-term period to import renewable energy, but may be unable to do so on a constrained path if they are unable to utilize the capacity they are freeing up by the request to undesignate.

936. Several petitioners request rehearing or clarification with respect to the Commission's finding in Order No. 890 that network customers making firm third-party system sales from network resources must undesignate each portion of each resource supporting the third-party sales. [344] Petitioners generally argue that requiring a network customer to keep track of the individual generating units and amounts of generation from each unit being used to supply a system sale is unduly burdensome or impossible. South Carolina E&G argues that, between the scheduling deadline and the time when service commences, any number of events can change the available generating units being dispatched, change the merit order dispatch, or cause dispatch of additional units. Joined by EEI, South Carolina E&G asks the Commission to allow slice of system sales from a generation fleet by undesignating the amount of the sale.

937. Duke states that the Commission's policies are clear that for off-system system sales a generating resource must be identified on a specific basis for purposes of arranging point-to-point transmission service to support the off-system sale. However, with regard to identifying which generating units will be used to generate the energy to make on-system system sales, Duke argues that the Commission has never required that particular units or portions of units be identified and undesignated on a unit-by-unit basis. Duke contends that all generating units that comprise the ''system'' are used to serve all loads, and the undesignation process should occur through the recognition that a share of the generation system is used for retail native load and a share is used for wholesale native load (*i.e.*, requirements customers) and off-system firm load. Duke maintains that this approach is reasonable and ensures that the transmission provider is not double-counting or double-reserving transmission capacity needed to serve such loads, and is purchasing point-to-point service that is needed.

938. E.ON U.S. argues that the Commission has provided insufficient protection for LSEs and others that may need to recall undesignated resources for use to supply native load during times of system emergencies. E.ON U.S. asks the Commission to make clear in the *pro forma* OATT that the obligation to serve native load may require the redesignation of network resources in times of system emergency. Absent such a clarification, E.ON U.S. argues that LSEs will be reluctant to make network resources available to serve the market and, in a time of emergency, confusion may occur regarding the proper procedure for redesignating resources.

939. Pacific Northwest IOUs and South Carolina E&G request clarification in their post-technical conference comments that a network resource does not have to be undesignated before it is used to support the provision of reserve energy under a regional reserve sharing arrangement. E.ON U.S. requests similar clarification, arguing that flexible undesignation rules are necessary to allow utilities to quickly respond under reserve-sharing arrangements. Together, they argue that the failure to provide such clarification, and the related complications and potential sanctions, could impede or destroy reserve sharing arrangements and/or seriously imperil system reliability. South Carolina E&G proposes that the Commission expressly redefine network load under the *pro forma* OATT to include responses by the transmission provider to requests for emergency assistance or calls for reserves under reserves sharing agreements. If the Commission concludes that the undesignation requirements apply to designated network load used for reserve sharing purposes, E.ON U.S. proposes to post on OASIS information regarding its reserve sharing events within five days of the end of each month in which an event occurred. E.ON U.S. states that the particular units used to meet its reserve sharing obligation are not known until it performs an after-the-fact, monthly allocation of the highest-cost resources to off-system sales.

940. MidAmerican requests clarification that, during the period until improved OASIS functionality is available for designating and undesignating network resources, electronic transmissions and e-mail are acceptable means of designating and undesignating network resources. MidAmerican argues that electronic transmittals are similar to the already accepted telefax and recorded telephone line procedures, in that they provide a quick, efficient means of communication that can be readily stored.

941. NRECA requests rehearing of the Commission's determination that transmission providers have the discretion to deny undesignations of network resources. NRECA argues that the Commission has given transmission providers the ability to unduly discriminate against its wholesale customers (*i.e.*, its direct competitors). Because the transmission provider is not likely to deny its own undesignation requests, NRECA contends that comparability requires that it not be allowed the ability to deny undesignation requests of its network customers. NRECA argues that while the actual scheduling of a resource could affect reliability, there should be no reliability effects from the mere designation or undesignation of a resource. NRECA contends that there are many other standards and procedures in place to protect against insufficient capacity.

942. If the Commission retains the ability to deny a request to terminate the designation of a network resource, NRECA asks the Commission to at least require that denials come at the direction of the reliability coordinator, rather than the transmission provider. NRECA argues that denying the undesignation of a network resource is akin to designating the resource as a ''must-run'' generating resource. If the resource is owned by the network customer, NRECA maintains that the reliability coordinator should be able to designate the unit as a reliability-must-run unit and compensate the network customer for its dispatch. If the resource is not owned by the network customer, NRECA argues that nothing in the FPA authorizes the Commission to require the network customer or the owner of the resource to continue to contract for service with each other or use any particular capacity for a specific purpose.

943. TAPS seeks clarification that a transmission provider could deny a request to undesignate a network resource only in the context of requests for temporary undesignation. TAPS argues that there are circumstances in which a resource is simply not available because, for example, it is incapable of continued operation or no longer economically viable or, in the case of a purchase, the contract has ended.

944. MidAmerican asks that transmission providers be required to explicitly approve or deny requests to undesignate network resources and that the timing of action on undesignation requests be made consistent with the timing requirements to designate a network resource. MidAmerican argues that clarification is necessary to avoid confusion when one customer is undesignating a network resource so that another customer may designate it,

[344] *E.g.,* Duke, EEI, and South Carolina E&G. Pacific Northwest IOUs raise similar issues in their post-tech conference comments.

otherwise a customer could be attempting to designate a resource before the request to undesignate has been addressed.

945. Bonneville argues that the Commission should not require network resources to be temporarily undesignated to make firm third-party power sales if the transmission provider's ATC methodology already assures that ATC has not been withheld to accommodate the underlying designation. Bonneville maintains that its transmission customers usually designate as network resources power purchase agreements sourced from the resources that comprise the interconnected hydroelectric system. Bonneville argues that its ATC methodology, which is based on historical usage data, addresses the Commission's concerns about the availability of ATC without further requiring network resources to be undesignated prior to making third-party sales from those resources.

Commission Determination

946. We disagree with Bonneville's argument that a customer undesignating a network resource should be first-in-line for the transmission capacity freed up by such a designation. While it may be true in some circumstances that a network customer would choose not to undesignate a resource if there is insufficient ATC to accommodate a desired alternative transaction, it does not follow that the network customer's alternative transaction should be put ahead of other competing requests in the queue. That would undermine long-standing policies governing the priority of service requests and unduly preference network customers. The Commission rejects similar requests by point-to-point customers to be first in line for ATC in section III.D.4.b.

947. With regard to the undesignation of units used to supply system sales, we clarify that portions of the seller's individual network resources supporting a sale of system power do not need to be undesignated so long as the system sale is itself designated as a network resource by the buyer. Instead, the seller should undesignate a portion of its system equal to the amount of the system sale, but which is not attributed to any specific generators. If the system sale is not designated as a network resource by the buyer, the seller must submit undesignations for each portion of each resource supporting the third-party sale. Since we believe most, if not all, system sales sourced from designated network resources are themselves designated as network resources by the buyer, we expect that few system sales will require undesignation on a unit-by-unit basis.

948. As we reiterate in section III.D.9.c there is also no need to undesignate network resources prior to making sales that permit curtailment without penalty to serve the seller's native load.[345] Since there is no need to undesignate resources to make such sales, there is no corresponding need to redesignate those resources in times of emergency when power is recalled to serve native load. We therefore disagree with E.ON U.S. that special redesignation procedures are necessary for LSEs selling recallable energy. In response to Pacific Northwest IOUs and South Carolina E&G, we amend sections 1.26 and 30.4 of the *pro forma* OATT to make clear that network resources do not have to be undesignated before they are used to support the provision of reserve energy under a Commission-approved reserve sharing agreement.

949. In response to MidAmerican's request, we clarify that, pending implementation of the new OASIS functionality, submission of requests to designate and undesignate network resources may be provided by any appropriate electronic procedures established by the transmission provider, or by telephone or telefax as provided in Order No. 890.

950. We grant NRECA and TAPS' request for rehearing of the Commission's decision in Order No. 890 to allow transmission providers to deny requests to terminate network resource designations in certain situations. Upon consideration of petitioners' arguments, we agree that it is not appropriate to allow the transmission provider to deny undesignation, effectively requiring the network customer to continue to make available a resource that the customer is unable to, or no longer wishes to, make available. Reliability problems caused by the lack of available resources should be dealt with through other means, such as negotiation of must-run service agreements. In light of this decision, MidAmerican's request to establish a time by which a transmission provider must act on a request to terminate the designation of a network resource is rejected as moot.

951. We disagree with Bonneville that the *pro forma* OATT should be amended to allow for firm third-party sales from a network resource without first undesignating the network resource. If the particular ATC methodology used by the transmission provider allows for flexibility in implementing this requirement, the transmission provider may propose a variation to the *pro forma* OATT in an FPA section 205 filing. Any such request should adequately address the Commission's concern, as stated in Order No. 888, that network customers may (absent a prohibition on network resources including any portion of a resource that was committed for sale to a third party) have the incentive to specify unlimited *generation* resources to be integrated into their load without any commensurate financial obligation, given that network transmission service is billed on a *load* ratio basis.[346]

6. Clarifications Related to Network Service

a. Secondary Network Service

952. In Order No. 890, the Commission declined to adopt further limitations to the use of secondary network service under section 28.4 of the *pro forma* OATT, which allows a network customer to deliver energy to its network load from non-designated network resources on an as-available basis without additional charge. Although the Commission had proposed in the NOPR to limit the proper use of secondary network service to deliveries of economy energy only, upon review of comments submitted on this issue the Commission concluded that there were instances outside of the proposed definition of economy energy that warranted the use of secondary network service. The Commission therefore decided to retain the existing section 28.4 of the *pro forma* OATT that allows the use of secondary network service ''to deliver energy to its Network Loads.''

Requests for Rehearing and Clarification

953. Idaho Power asks the Commission to clarify the showing that transmission customers must make to demonstrate that they are using secondary network service properly or not using secondary network service to support off-system sales. Idaho Power states that several commenters lamented in response to the NOPR the difficulties of making the calculations necessary to demonstrate that secondary network service is not being used to support off-system sales. Idaho Power contends that the Commission has never clearly articulated the test used to determine improper use of network service. Although Idaho Power acknowledges that the Commission has provided some guidance on these issues in audit and investigation reports, Idaho Power states

[345] *See* Order No. 890 at P 1459; *see also WPPI* 84 FERC at 61,152. Curtailment contemplates a reduction in service as a result of system reliability conditions, not economic reasons.

[346] *See* Order No. 888 at 31,753–54.

that it is unclear to what extent the Commission intends language in such reports to apply beyond the context of the particular audit or investigation.

954. Idaho Power suggests that an economic test would not be precise enough to address all the circumstances where network and secondary transmission should be used. Idaho Power asks that the Commission instead consider three factual questions to evaluate the proper use of secondary network service: Whether the utility's decisions were intended to maintain a balanced portfolio for service to load; whether the off-system sale was made at a time when the utility's resources exceeded its expected load and needed to balance its portfolio; and, whether the utility either actually needed the imported energy to serve load or needed the imported energy to replace a more expensive resource that otherwise would have been used to serve load. If the answer to these questions is ''yes,'' then Idaho Power argues that the use of network or secondary transmission should always be allowed to import energy.

955. Idaho Power also asks the Commission to articulate the types of records it expects a utility to maintain in order to document the use of its transmission network in compliance with Commission requirements. In Idaho Power's view, clarification of the rules and corresponding documentation requirements will allow utilities and other network customers to become more comfortable using secondary network service rather than buying excessive amounts of point-to-point transmission.

Commission Determination

956. The Commission affirms the decision in Order No. 890 to retain the existing test for eligibility to use secondary network service, *i.e.*, when energy is delivered to serve network loads. In rejecting the proposed restriction to deliveries of economy energy, the Commission recognized that there may be instances that warrant the use of secondary service in order to serve network loads reliably that would not satisfy an economic test, as Idaho Power suggests. The Commission declined to adopt other restrictions on the use of secondary network service proposed by commenters, expressing concern that the proposals could preclude legitimate use of secondary network service.

957. We similarly conclude that the alternative three-part factual test proposed by Idaho Power might not reflect all of the factors to be considered in determining whether a particular use of secondary network service was to deliver energy to network loads. The Commission did not preclude in Order No. 890 consideration of whether the delivery in question is economic energy and, instead, determined that restricting the use of secondary network service only to economic energy would be too severe. The primary focus of the Commission's analysis is whether the energy delivered using secondary network service was intended to serve network load. Whether a delivery in question is for economic energy may very well be relevant when considering intent, but so would contemporaneous documentation and other evidence. We will continue to address the appropriate use of secondary network service on a case-by-case basis, as in *MidAmerican,*[347] which we intend to serve as guidance to the industry regarding the appropriate use of secondary network service and the documentation that would be relevant for analysis.

b. ''On an as-available basis''

958. The Commission clarified in Order No. 890 that secondary service must be requested in accordance with section 18, including the timing restrictions set forth in section 18.3 of the *pro forma* OATT. The Commission explained that secondary service is on an as-available basis and that network customers should not be allowed to lock in such service in advance of other non-firm uses of available transmission. The Commission concluded that allowing lower priority secondary service to have a scheduling advantage over non-firm transmission would be inappropriate and would discourage the use of non-firm transmission service.

Requests for Rehearing and Clarification

959. Several petitioners request clarification regarding the priority level of secondary network service in relation to non-firm transmission service. NRECA, Southern, and TDU Systems ask the Commission to clarify that secondary service has a higher priority than non-firm point-to-point service. These petitioners state that section 28.4 of the pro forma OATT grants secondary service a higher priority than all non-firm point-to-point service and that the Commission's reference to secondary network service as ''lower-priority'' in Order No. 890 is incorrect and contradictory of Order No. 888. Without a higher priority for secondary network service, these petitioners contend that network customers located in constrained regions who are forced to rely on secondary service will be worse off and reliability will be impaired.

960. Joined by TAPS, NRECA argues that application of the scheduling requirements for non-firm point-to-point service to network customer reservations of secondary service would present a serious set-back for LSEs. NRECA states that its members commonly use secondary service to import long-term firm power from other states into their home states in order to serve native load. NRECA argues that this use of secondary service could not happen if network customers were held to the timing restrictions in section 18.3. NRECA contends that precluding network customers from acquiring secondary service to coincide with long-term generation requirements, but before actual use of the transmission, would contradict Congressional intent to preserve and enhance network service to native load.

961. NRECA further contends that there is no evidentiary record for finding that the existing practice of scheduling secondary service without regard to the time restrictions of section 18.3 has ''discouraged'' the use of non-firm transmission service or minimized associated revenue credits. Even if that is the case, NRECA argues that secondary network service customers should have priority and any marginal amount of foregone revenues is justified by more reliable, economic service for LSEs. Because network customers pay a load ratio share of total transmission costs regardless of whether their energy is coming from designated network resources or non-designated network resources on an as-available basis, NRECA concludes that network customers use the transmission system in a fundamentally different way from non-firm users and, therefore, they should not be held to the same timing restrictions in 18.3 that apply to non-firm customers.

962. TAPS argues that, as long as network customers bear a full share of the costs of operating the entire system, they should have first call on non-firm use, just as secondary network service is the last non-firm use to be curtailed in response to constraints. In the event the Commission denies rehearing on this issue and retains the new timing restrictions on secondary service, TAPS asks that transmission providers also be required to abide by those same requirements when they seek to use an undesignated resource (or the undesignated portion of a resource) to service their native load.

[347] *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 at P 6 (2005) (*MidAmerican*).

Commission Determination

963. The Commission grants clarification of the reference to ''lower-priority'' secondary network service in paragraph 1606 of Order No. 890, which was intended to distinguish secondary network service from firm transmission service, not non-firm transmission service. Section 28.4 of the *pro forma* OATT affords secondary service a higher curtailment priority than any non-firm point-to-point service and the Commission did not intend to imply otherwise in Order No. 890. We disagree, however, that secondary service should be allowed a higher scheduling priority compared to all other non-firm service. Secondary service is on an ''as available'' basis and, therefore, network customers should not be allowed to lock in such service in advance of other non-firm uses of available transmission.

964. Petitioners' arguments to the contrary are misplaced. Although FPA section 217 does address LSE uses of the transmission systems, the focus of that provision is on the use of firm transmission, not non-firm uses such as secondary network service. The fact that network customers pay a load ratio share of transmission costs does not grant them superior rights when scheduling firm transmission, nor should it justify superior rights when scheduling uses of the transmission system other than firm uses. Any request for secondary network service therefore must be made in compliance with section 18, including the timing restrictions set forth in 18.3, of the *pro forma* OATT. In response to TAPS, we reiterate that section 28.2 of the *pro forma* OATT requires the transmission provider to designate resources and loads in the same manner as any network customer.

c. Behind the Meter Generation and Uses of Point-To-Point Service

965. The Commission declined to require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs, stating that commenters had not provided any different arguments not fully addressed in Order No. 888. The Commission explained that the existing *pro forma* OATT already allowed transmission customers to exclude the entirety of a discrete load from network service and serve such load with the customer's behind the meter generation and point-to-point transmission service as necessary, thereby reducing the network customer's load ratio share. The Commission concluded it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis.

Requests for Rehearing and Clarification

966. Washington IOUs contend that the language added to section 30.4 of the pro forma OATT in Order No. 890 appears to permit a transmission provider or network customer to take point-to-point service to deliver power from remote network resources to loads in certain instances. Washington IOUs ask the Commission to clarify that a transmission provider or network customer may use short-term firm point-to-point service to serve native load or network load, respectively. Washington IOUs state that there are at least two events in which the use of point-to-point service to serve native or network load is needed and appropriate: the need to import power when it is unclear whether or not the power will be deemed to be used to serve native or network load because of its relative cost; and the need to import power reliably from non-designated network resources in order to serve native or network load, instead of relying on secondary network service. In their view, a restriction on the use of point-to-point service would prevent the transmission provider and network customer from competing for scarce transmission capacity in order to serve their native or network load.

967. Idaho Power similarly asks the Commission to clarify whether a network customer or transmission provider could use point-to-point transmission to serve load in addition to, and not in place of, paying its full load ratio share for use of the network. Idaho Power contends that a transmission provider or network customer should have the option to compete in the market for point-to-point service when it is not sure at the time of a purchase whether the energy will be needed for load or sold off-system as surplus, provided they pay the full value of point-to-point service. Alternatively, Idaho Power requests the Commission clarify that the network customer and the transmission provider may procure firm point-to-point service in order to serve native and network load when the utility requires capacity in addition to the existing network reservations or secondary transmission over an interface. In order to ensure that network and secondary transmission rights are not being used to support off-system sales, Idaho Power contends that the use of network transmission rights must be minimized and used in combination with point-to-point service.

968. Idaho Power also requests clarification that the following examples are considered proper uses of network transmission, secondary transmission and point-to-point transmission. First, use of point-to-point transmission to accomplish an off-system sale entered into at a time the utility was forecasted to be long, even if followed by a subsequent purchase to serve load using secondary network service or point-to-point transmission if the utility becomes short. Second, use of a combination of network service, secondary network service, or point-to-point transmission for a purchase at a time the utility was forecasted to be short, even if followed by a subsequent sale using point-to-point transmission from a portion of that resource that becomes excess due to a drop in forecasted load. Third, and related, use of network transmission for a purchase expected to serve load, even if followed by a subsequent sale using point-to-point service from a portion of that resource that becomes excess in real-time. Fourth, use of point-to-point service to purchase economic energy to serve network load in conjunction with an off-setting undesignation of network resources and sale of energy off system using point-to-point transmission. Finally, use of secondary network service to purchase economic energy to serve network load in conjunction with an off-setting undesignation of network resources and sale of energy off system using point-to-point transmission. Idaho Power contends that only the last example should involve an economic test to demonstrate that the imported resource will displace a resource in the utility's load service stack of resources.

969. TAPS and FMPA argue that the Commission failed to consider in Order No. 890 the circumstance when it is physically impossible for the transmission system to actually deliver a customer's full load, which they contend was not addressed in Order No. 888.[348] TAPS states that the Commission's proposed solution of the exclusion of the entirety of a discrete load from network service is no help to a customer that is served through a single delivery point and, therefore, has no discrete load that could be service through a combination of point-to-point service and behind the meter generation while other load takes network service. FMPA argues that it is unjust to charge a customer for service that cannot be provided and, therefore, there should be an exception to load ratio share pricing

[348] *Citing Florida Mun. Power Agency* v. *FERC*, 411 F.3d 287, 291 (D.C. Cir. 2005).

when the transmission provider is unable to serve the network customer's entire load.

Commission Determination

970. As stated in Order No. 890, the *pro forma* OATT permits transmission customers to exclude the *entirety* of a discrete load from network service and serve such load with the customer's behind the meter generation and through any needed point-to-point transmission service, thereby reducing the network customer's load ratio share.[349] In other situations, use of point-to-point service by network customers is in addition to network service and therefore does not serve to reduce their load ratio share. As the Commission concluded in Order No. 888–A, transmission customers ultimately must evaluate the financial advantages and risks and choose to use either network integration or firm point-to-point transmission service to serve load.[350] Any alternative transmission provider proposals for behind the meter generation treatment will be reviewed on a case-by-case basis.[351]

971. With regard to concerns of insufficient transmission to serve the network customer's full load, we fail to understand how, under normal circumstances, the transmission provider has no capacity to service a load that has been designated by the network customer. Once a load has been designated, it is the obligation of the transmission provider to serve that load and to plan its system so that the load can be accommodated in the future. To assist the transmission provider in fulfilling that obligation, network customers are required to provide load forecasts to the transmission provider each year. The transmission planning reforms adopted in Order No. 890 will add greater transparency to this planning process, better enabling network customers to understand how their needs are reflected in the development of the transmission system. To the extent a transmission provider is unable to satisfy its obligation to serve a designated network load, it is more appropriate to address that situation on a case-by-case basis.

972. The Commission also declines to address here the hypothetical scenarios offered by Idaho Power. Any determination regarding the appropriate use of secondary, network, or point-to-point service will depend upon the facts surrounding the use of such services. While load forecasts may change and weather related incidents may occur, with corresponding implications for a utility's purchasing activities, it is most appropriate for the Commission to consider whether a particular transaction is an appropriate use of secondary network service based on the facts and circumstances surrounding the transaction, as discussed above.

7. Transmission Curtailments

973. The Commission did not propose in the NOPR, or adopt in Order No. 890, any changes to the terms and conditions under which a transmission provider may curtail service to maintain reliable operation of the grid, as set forth in sections 13.6 and 14.7 for point-to-point service and section 33 for network service. The Commission did, however, conclude that the posting of additional curtailment information is necessary to provide transparency and allow customers to determine whether they have been treated in the same manner as other transmission system users, including customers of the transmission provider. Accordingly, the Commission required transmission providers, working through NAESB, to develop a detailed template for the posting of additional information on OASIS regarding firm transmission curtailments, including all circumstances and events contributing to the need for a firm service curtailment, specific services and customers curtailed (including the transmission provider's own retail loads), and the duration of the curtailment.

Requests for Rehearing and Clarification

974. Powerex claims the Commission improperly rejected its request that the *pro forma* curtailment provisions be modified to provide for *pro rata* curtailment based on a customer's reserved capacity rather than its scheduled capacity. Powerex states that the Commission appears to have misunderstood its proposed two-stage curtailment procedure, which was rejected for having the potential to impair reliability since the amount of capacity curtailed using that approach would not address the actual power flows and, therefore, could be less than required to relieve the overloaded facility. Powerex explains that the proposed two-stage process pertained solely to the timeframe before power is actually flowing. Powerex further states that *pro rata* curtailments based on reservation capacity would be made prior to the energy scheduling and tagging deadline (*e.g.*, 20 minutes before the operating hour), that the transmission provider would compare a customer's individual schedule to its reduced/curtailed rights, and, if the customer's scheduled quantities fall within its reduced rights, that schedule would flow uncut. After calculating the total capacity scheduled following the application of the *pro rata* curtailment, Powerex proposes that any excess transmission be allocated back on a *pro rata* basis to transmission customers whose schedules were cut below their reduced rights. Powerex states that this would in no way affect curtailments to actual power flows. Powerex suggests that curtailment within the hour, due to the limited time available to affect relief, should continue to be allocated based on actual schedules.

975. Powerex contends that the Commission mistakenly concluded that Powerex's proposal would adversely impact reliability, arguing that the amount of capacity curtailed under the two-stage process would be no different from the amount of capacity the transmission provider believes is necessary to address the constraint and that the capacity would be more equitably and economically cut according to the transmission customers' reserved quantities rather than the scheduled quantities. Powerex states that it is not aware of a single commenter that provided any evidence that the above modification would be detrimental in any way to reliability, nor did the Commission provide any evidentiary support for its response.

976. E.ON U.S. requests clarification of the correct order of curtailments given the addition of conditional firm point-to-point transmission service. Specifically, E.ON U.S. requests clarification regarding the curtailment priority of the different conditional firm options, *i.e.*, conditions based on an annual number of hours and conditions based on specific system conditions.

Commission Determination

977. The Commission rejects Powerex's request to modify the curtailment provisions of the *pro forma* OATT to provide for *pro rata* curtailment based on a customer's reserved capacity rather than its scheduled capacity. Although Powerex addresses in its request for rehearing the Commission's initial concern regarding the proposal,[352] we continue to believe that the proposal would have a potentially adverse impact on reliability. Powerex's proposal would

[349] *See* Order No. 890 at P 1619.

[350] Order No. 888–A at 30,260–61.

[351] *See, e.g., PJM Interconnection, L.L.C.*, 113 FERC ¶ 61,279 (2005).

[352] *See* Order No. 890 at P 1629 (stating that the amount of capacity actually curtailed under the Powerex proposal might be less than required to relieve the overloaded facility).

greatly increase the complexity of scheduling transactions at or near real-time operations, threatening reliability without providing significant competitive benefits. Powerex has taken a complex issue and presented it in two simple steps, leaving out the details of how the transmission operators could obtain all the necessary information required to make on-the-spot decisions, perform the analyses to determine whether each schedule flow fully utilizes its respective reservation, reallocate unused reserved capacity, and curtail transactions without impairing reliability. We thus reject the Powerex's request for rehearing in this regard.

978. In response to E.ON U.S., we reiterate that the Commission adopted a secondary network curtailment priority to apply for the hours or specific conditions when conditional firm service is conditional. During non-conditional periods, conditional firm service curtailment is treated consistent with curtailment of other long-term firm service.[353] We reiterate that Order No. 890 did not change the terms and conditions under which a transmission provider may curtail service to maintain reliable operation of the grid or change the priority of curtailment for any type of transmission service. Rather, conditional firm point-to-point service, as adopted in Order No. 890, fits within the existing curtailment priorities and constructs.

8. Standardization of Rules and Practices

a. Business Practices

979. In Order No. 890, the Commission adopted the NOPR proposal to continue to require that only those rules, standards, and practices that significantly affect transmission service be incorporated into a transmission provider's OATT. The Commission affirmed the use of a ''rule of reason'' to determine what rules, standards, and practices significantly affect transmission service and, as a result, must be included in the transmission provider's OATT.

980. Regarding rules, standards, and practices that relate to transmission service, but are not included in the OATT, the Commission required transmission providers to post this information on their public Web sites and make it accessible via OASIS. The Commission made this requirement applicable to all such rules, standards, and practices, currently written or otherwise.[354] The Commission stated that it would not be appropriate to place the rules, standards, and practices only on OASIS, as some transmission providers use certificates to restrict access to their OASIS sites. The Commission amended section 4 of the *pro forma* OATT to establish this posting requirement.

981. The Commission also required each transmission provider to post on its public Web site, with a corresponding link on OASIS, a statement of the process by which the transmission provider will amend the rules, standards, and practices that relate to transmission service, but which are not included in the OATT. The Commission stated that this process must include a mechanism to provide reasonable notice of any proposed changes to a posted business practice and the respective effective date of such change.[355] Section 4 of the *pro forma* OATT was further amended to formalize this posting requirement.

982. Finally, the Commission adopted the NOPR proposal to amend the *pro forma* OATT by including a new Attachment L specifying the qualitative and quantitative criteria that the transmission provider uses to determine the level of secured and unsecured credit required. The Commission determined that Attachment L must contain the following elements: (1) A summary of the procedure for determining the level of secured and unsecured credit; (2) a list of the acceptable types of collateral/security; (3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements; (4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements; (5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and (6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination. The Commission stated that the transmission provider could supplement Attachment L with a credit guide or manual to be posted on OASIS.

Requests for Rehearing and Clarification

983. TDU Systems contend that the Commission's filing standard suggests that the ''rule of reason'' test will only come into play *after* it has determined that a particular practice is one that significantly affects transmission service. TDU Systems argue that, once the Commission has determined that a practice significantly affects rates and services, the only remaining question is whether the practice is realistically susceptible of specification and is not so generally understood in any contract or arrangement as to render recitation superfluous.[356] TDU Systems contend that Order No. 890 is an unexplained departure from prior precedent and that the Commission failed to justify its limitation on the data to be included in the OATT.

984. In order to increase certainty, TDU Systems also requests that the Commission specify in advance the different categories of transmission provider issuances that the Commission expects to see in the tariffs. At a minimum, TDU Systems asks that the Commission clarify that any rule, standard, or practice that can serve to limit a transmission customer's access to transmission service is one that significantly affects transmission service and, therefore, should be included in the OATT.

985. Old Dominion requests that the Commission clarify that, for individual transmission-owning members of an RTO that do not maintain their own OATT, the transmission owners must comply with the requirements of Order No. 890 by including in the RTO's OATT any rules, standards and practices that affect transmission service that are either different from or an expansion upon those in the RTO's OATT. Old Dominion states that this is necessary because individual transmission owners' planning criteria and business practices can limit access to transmission service in the same manner as those of the RTO.

986. NRECA states that it supports the Commission's decision to require each transmission provider to post on its public Web site (with a corresponding link on OASIS) all rules, standards or business practices that relate to the terms and conditions of transmission service, if not already stated in the OATT itself. NRECA contends, however, that the Commission's subsequent discussion of transmission providers' credit guides or manuals seemingly allows that information to be

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[353] *See id.* at P 1074.

[354] With respect to the business practices developed by NAESB, the Commission noted that there may be copyright restrictions that limit the transmission provider's ability to post those practices on its own Web site. In such instances, the Commission stated its expectation that the transmission provider will reference any NAESB practices it uses and provide a link on its public Web site to the copyrighted material on the NAESB Web site.

[355] The Commission permitted transmission providers to adopt such additional procedures they deem appropriate, such as opportunities for comment to proposed changes to rules, standards, and practices.

[356] *Citing City of Cleveland* v. *FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) (*City of Cleveland*).

posted only on OASIS.[357] Because credit is such an important potential barrier to transmission access, NRECA maintains that it is critical for the details of the credit criteria and methodologies to be posted on the public Web site of the transmission provider, with a link on OASIS. NRECA also contends that a statement should be added to the first paragraph of Attachment L explicitly clarifying that the credit review procedures and criteria may not unfairly disadvantage public power entities or other customer groups having unconventional financing or business structures.

987. Southern requests that the Commission grant rehearing to allow a transmission provider that does not restrict access to its OASIS site the option of posting rules, standards and practices relating to transmission service on its OASIS with a link to such information on its public Web site. Southern maintains that permitting transmission providers that do not restrict access to their OASIS to make required postings on OASIS would satisfy the Commission's objective to provide public access to such information. Southern argues that not allowing such flexibility would be arbitrary and capricious.

Commission Determination

988. The Commission did not intend, as TDU Systems suggest, that the Commission must first determine that a particular practice significantly affects transmission service before it applies the ''rule of reason.'' In Order No. 890, the Commission ''affirm[ed] the use of a ''rule of reason'' to determine what rules, standards, and practices significantly affect transmission service and, as a result, must be included in the transmission provider's OATT.'' [358] Specifically, the ''rule of reason'' requires ''recitation of only those practices that affect rates and services significantly, that are realistically susceptible of specification, and that are not so generally understood as to render recitation superfluous.'' [359] The Commission intends to continue to use the ''rule of reason'' for this purpose, consistent with its statutory responsibility and precedent.

989. We decline to specify in advance the particular categories of rules, standards, and practices that must be documented in the transmission provider's OATT. Although rules, standards, and practices that limit a transmission customer's access to transmission service may very well have a significant effect on transmission services, and therefore should be in the OATT, any attempt to list the specific categories of rules, practices and standards that must be included in an OATT would be over- or under-inclusive as applied to a particular transmission provider. The Commission believes that, through application of the ''rule of reason,'' we will be better able to identify those rules, standards and practices that significantly affect transmission service and, as a result, are required to be in each transmission provider's OATT.

990. In response to Old Dominion, we reiterate that each ISO and RTO must include in its OATT *all* of the rules, standards and practices that significantly affect the transmission service provided by the ISO or RTO and must electronically post *all* of the rules, standards and practices that relate to transmission service, but which are not included in the OATT. To the extent any of the transmission-owning members of the ISO or RTO have additional rules, standards and practices that significantly affect, or relate to, the transmission service being provided by the ISO or RTO, the ISO or RTO must include such rules, standards and practices in its OATT or electronic postings, as relevant. Transmission customers must be able to understand the rules, standards and practices that affect or relate to the service being provided by the transmission provider, even if such rules, standards or practices are developed or implemented by third parties.

991. We agree with Southern's request for rehearing to allow a transmission provider that does not restrict access to its OASIS site the option of posting rules, standards and practices relating to transmission service on its OASIS with a link to such information on its public Web site. The Commission is sympathetic to Southern's concern and agrees that section 4 of the *pro forma* OATT, as revised by Order No. 890, is overly restrictive. The Commission's purpose in revising section 4 was to ensure that the public has unrestricted electronic access to the transmission provider's rules, standards and practices that are not included in its OATT. The Commission concludes that the transmission provider should be free to place this information on OASIS, its public Web site or other suitable electronic platform as long as the transmission provider provides, both on OASIS and on its public Web site, an electronic link to the information. We have revised section 4 accordingly.

992. We also agree with NRECA that, in Order No. 890, the Commission appears to allow the transmission provider to post its credit guides or manuals only on OASIS.[360] This was not our intent. The Commission considers credit guides and manuals containing more detailed information than that required in Attachment L to be rules, standards or practices that relate to transmission service, that not be included in the transmission provider's OATT. We clarify that the transmission provider must electronically post such credit guides and manuals and provide a link to that information on its public Web site and OASIS. We deny as unnecessary NRECA's request to add a statement to Attachment L regarding application of credit review procedures and criteria to customer groups with unconventional financing or business structures. The Commission already provided in Order No. 890 that transmission providers must consider both quantitative and qualitative factors so that the particular circumstances surrounding public power entities can be recognized when analyzing their creditworthiness.[361]

b. Limitation on Liability

993. In Order No. 890, the Commission declined to amend the liability protections found in the *pro forma* OATT for the same reasons that the Commission rejected similar proposals in the past.[362] The Commission relied upon the reasoning found in Order Nos. 888–A, 888–B, 2003,[363] the Reliability Policy Statement,[364] and Commission precedent.[365] The Commission explained that the *pro forma* OATT was not intended to address liability issues and that liability was a separate issue from indemnification.[366] The Commission further explained that

[357] *Citing* Order No. 890 at P 1657–58.

[358] *Id.* at P 1649.

[359] *Public Serv. Co. of Colo.,* 67 FERC ¶ 61,371 at 62,267 (1994) (quoting *City of Cleveland,* 773 F.2d at 1376).

[360] *See* Order No. 890 at P 1657–58.

[361] *See id.* at P 1659.

[362] *See, e.g., Southwest Power Pool, Inc.,* 113 FERC ¶ 61,287 (2005); *Southern Company Services, Inc.,* 113 FERC ¶ 61,239 (2005); *Nevada Power Co.,* 99 FERC ¶ 61,347 (2002); *Arkansas Louisiana Gas Co.* v. *Hall,* 7 FERC ¶ 61,175, *reh'g denied,* 8 FERC ¶ 61,039 (1979).

[363] Order No. 2003 at P 636; Order No. 2003–A at 31,162.

[364] Policy Statement on Matters Related to Bulk Power System Reliability, 107 FERC ¶ 61,052 (2004) (Reliability Policy Statement).

[365] *See, e.g., Northeast Utilities Services Co.,* 111 FERC ¶ 61,333 (2005) (*Northeast Utilities*); *Southwest Power Pool, Inc.,* 112 FERC ¶ 61,100 at P 39 (2005); *Southern Company Services, Inc.,* 113 FERC ¶ 61,239, at P 7 (2005).

[366] *See* Order No. 888–A at 30,301 and Order No. 888–B at 62,081 (section 10.2 of the *pro forma* OATT).

transmission providers were not precluded from relying on state laws that protected utilities or others from claims founded in ordinary negligence.[367] The Commission declined to adopt a uniform federal liability standard and decided that, while it was appropriate to protect the transmission provider through force majeure and indemnification provisions from damages or liability when service is provided by the transmission provider without negligence, it would leave the determination of liability in other instances to other proceedings.[368]

Requests for Rehearing and Clarification

994. Washington IOUs request that the Commission grant rehearing and establish a uniform liability provision in the *pro forma* OATT that limits transmission provider liability except in instances of gross negligence or willful misconduct. In their view, enactment of mandatory reliability standards under FPA section 215, the threat of civil penalties and other remedial actions, and state oversight all provide appropriate incentives for utilities to exercise due care in the operation of their systems. Washington IOUs argue that state protections do not appear to be sufficient to protect a transmission provider against outage liability since they have arisen in the context of claims by retail customers. They argue that granting liability limitations except in instances of gross negligence or intentional misconduct is appropriate given that outage liability is not necessary to ensure utilities operate their transmission systems reliably.

995. Washington IOUs also contend that limitations of liability can be effected by contracts, such as the *pro forma* OATT, under much state law. They argue that it is therefore arbitrary for the Commission to expect transmission providers to rely on state law for appropriate limitations of liability, while preventing the inclusion of provisions in the *pro forma* OATT to effectuate such limitations of liability. Washington IOUs also argue that the Commission has provided no good reason for approving limitations on liability for RTOs/ISOs, but not for other transmission providers. In their view, the policy concerns justifying liability limitations for utilities in RTOs/ISOs are identical to those confronting utilities in non-RTO/ISO areas.

Commission Determination

996. The Commission denies rehearing of the determination in Order No. 890 not to change the liability protections found in the *pro forma* OAAT. Washington IOUs raise no new arguments in support of their position. As the Commission explained in Order No. 890, proposals by public utilities to amend their OATTs to include limitations on liability will be considered on a case-by-case basis.[369] On review of such requests, the Commission will consider whether state laws provide inadequate protection from liability.[370] In response, Washington IOUs argue that state law protections appear to be insufficient because they arose in the context of claims by retail customers, yet petitioners offer no evidence that transmission providers are in fact precluded from relying on state law for liability protections. The potential for legal and regulatory gap is therefore not so great as to warrant inclusion of liability protections in the *pro forma* OATT for all transmission providers.

997. We also disagree that there is no reason to distinguish between RTOs/ISOs and other transmission providers in considering requests to amend the liability standard of their OATTs. The Commission has provided increased liability protection to RTOs/ISOs because they were created by and are solely regulated by the Commission and otherwise would be without limitations on liability.[371] Because Washington IOUs have failed to show that other transmission providers are similarly situated to RTOs/ISOs in this regard, we affirm the decision to continue to review on a case-by-case basis a request to amend the liability standard in a transmission provider's OATT.

9. OATT Definitions

998. In order to support the reforms adopted in Order No. 890 and otherwise clarify the requirements of the *pro forma* OATT, the Commission added and amended various definitions in the *pro forma* OATT. Petitioners have sought rehearing and clarification of certain of these definitions.

a. Affiliate

999. In order to support reforms associated with the distribution of operational penalties, the Commission adopted the following definition of Affiliate in the *pro forma* OATT: ''With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.''

Requests for Rehearing and Clarification

1000. EEI states that the term Affiliate is used in several provisions of the *pro forma* OATT that were not modified by Order No. 890. To avoid potential confusion, EEI requests that the Commission amend the *pro forma* OATT to capitalize every use of the term.

1001. APPA requests that, consistent with Order No. 888–A, the Commission clarify that public power joint agencies and their members are not corporate affiliates and, therefore, the definition of Affiliate does not apply to public power joint action agencies for the purposes of applying the Standards of Conduct. APPA notes that the Commission in Order No. 890 concluded that the definition of Affiliate does not apply to G&T cooperatives and their member distribution cooperatives. APPA argues that public power joint action agencies and their members are similarly situated to G&T cooperatives and their members and, as a result, the rationale set out in Order No. 888–A and Order No. 890 applies equally to public power agencies joint action agencies and their members.[372] APPA suggests Commission policy that supports not treating joint action agencies and their members as consisting of ''single economic units'' also supports not treating joint action agencies and their members as Affiliates.[373]

1002. E.ON U.S. requests guidance on how functionally unbundled transmission providers should treat their generation function for purposes of the *pro forma* OATT. E.ON U.S. states that its generation and transmission functions are owned by the same corporate entity, but are unbundled from each other for purposes of the Standards of Conduct. As a result, E.ON U.S. contends that its generation and transmission functions are not Affiliates because they are part of the same corporate entity. E.ON U.S. asks the Commission to clarify whether it intends to include a transmission provider's unbundled generation function within the definition of Affiliate even if the generation function is part of the same corporate entity.

Commission Determination

1003. The Commission grants rehearing, as requested by EEI, to amend

[367] Order No. 888–A at 30,301.

[368] Order No. 888–B at 62,081.

[369] *See* Order No. 890 at P 1675 (citing Reliability Policy Statement at P 40).

[370] *See Southern Company Services, Inc.,* 113 FERC ¶ 61,239 at P 7.

[371] *See id.*

[372] *Citing* Order No. 890 at P 1682 (*citing* Order No. 888–A at 30,286 and 30,366).

[373] *Citing Southwest Power Pool,* 112 FERC ¶ 61,355 at P 23–24 (2005).

the *pro forma* OATT such that every use of the term Affiliate is capitalized. We agree with APPA that members of an umbrella joint action agency are not Affiliates of the joint action agency within the meaning of the *pro forma* OATT. We clarify in response to E.ON U.S., however, that the transmission function and generation function of a single corporation are Affiliates. Each would be an entity under common control, notwithstanding the fact that they are within the same corporation.

b. Good Utility Practice

1004. In Order No. 890, the Commission incorporated the definition of reliable operation in FPA section 215 into the definition of Good Utility Practice in the *pro forma* OATT. As amended, the definition of Good Utility Practice is: ''Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).''

Requests for Rehearing and Clarification

1005. Xcel argues that revising the definition of Good Utility Practice to include compliance with the mandatory reliability standards of FPA section 215 inappropriately subjects transmission providers to two separate enforcement schemes for alleged violations of the reliability standards. Xcel suggests that the Commission eliminate from the definition of Good Utility Practice the reference to practices under FPA section 215. Xcel argues that this would not eliminate the obligation of transmission providers or transmission owners to comply with the mandatory reliability standards and, instead, would make such compliance subject to enforcement and potential penalties under one enforcement regime, as contemplated by Congress under the FPA.

1006. If the Commission does not eliminate the reference to practices required by section 215, Xcel asks the Commission to clarify that reliability standards that have not been approved under FPA section 215 would not be enforceable as an OATT violation.[374] Xcel also argues that a violation of a mandatory reliability standard approved by the Commission should be subject to enforcement only by the ERO or applicable RE under the compliance and enforcement scheme created by NERC and the Commission under FPA section 215. Xcel contends it would subject FERC-jurisdictional transmission providers to ''double jeopardy'' to allow a claim of an alleged violation of a mandatory reliability standard to be pursued in both an OATT enforcement proceeding and a section 215 enforcement proceeding. Finally, Xcel argues that in no event should an alleged violation of a mandatory reliability standard be subject to dual financial penalties through separate enforcement actions by the Commission for an OATT violation and by the ERO or RE for a reliability violation.

Commission Determination

1007. The Commission affirms the decision in Order No. 890 to incorporate within the definition of Good Utility Practice those practices required by FPA section 215(a)(4). Even without the revisions adopted in Order No. 890, the definition of Good Utility Practice would have incorporated each reliability standard approved by the Commission, since they represent practices in which the industry is required to engage. The Commission simply made this explicit in Order No. 890.

1008. As we explained in Order No. 693, however, the Commission does not believe it would be appropriate to retain a dual mechanism to enforce reliability standards both as Good Utility Practice and under FPA section 215.[375] The *pro forma* OATT only applies to entities subject to our jurisdiction as public utilities under the FPA, while section 215 defines more broadly our jurisdiction with respect to mandatory reliability standards. We therefore do not intend to enforce, as an OATT violation, compliance with any reliability standard approved by the Commission under section 215. It is more appropriate for the Commission to rely on its authority under section 215 to enforce compliance with mandatory reliability standards.

c. Non-Firm Sales

1009. In order to clarify the obligations of network customers under section 30.4 of the *pro forma* OATT, the Commission adopted the following definition of Non-Firm Sales in the *pro forma* OATT: ''An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.''

Requests for Rehearing and Clarification

1010. NRECA asks the Commission to clarify that a unit-contingent contract is not a Non-Firm Sale within the meaning of the *pro forma* OATT, which NRECA argues would make it ineligible for designation as a network resource. NRECA states that unit-contingent contracts excuse non-delivery only on account of constraints on the unit providing service and not, more generally, for ''any reason'' or ''no reason.'' NRECA contends that such contracts are sufficiently firm to be considered ''LU'' and ''IU'' service in FERC Form One Account 447 and should likewise not be considered Non-Firm Sales under the *pro forma* OATT.

1011. Southern questions whether system-firm sales that permit curtailment without penalty to serve the seller's native load should be treated as Non-Firm Sales for purposes of section 30.4 of the pro forma OATT. Southern states that the Commission has considered the purchase of a system-firm energy to be eligible for designation as a network resource,[376] but contends that it is ambiguous whether the seller should consider those sales as a Non-Firm Sale. Southern argues that treating such sales as Non-Firm Sales would assure internal consistency within the *pro forma* OATT, foster liquidity in short-term wholesale opportunity markets, and promote the efficient optimization of network resources.

1012. Washington IOUs argues that a contract that allows for interruption to serve native load should be considered a Non-Firm Sale even if there is a ''make whole'' penalty for the interruption. Washington IOUs argue that a requirement that sales from a designated network resource be recallable for service of native or network load without any financial consequences would constitute an unnecessary regulatory intrusion into wholesale electricity markets, and is not necessary for reliability purposes.[377]

1013. TAPS express similar concerns, asking the Commission to clarify that the definition of Non-Firm Sales includes transactions that permit interruption for any or no reason

[374] *Citing* Order No. 693 at P 302.

[375] *See id.*

[376] *Citing WPPI.*

[377] Washington IOUs argue that, now that the Commission has enforcement authority for reliability under section 215 of the FPA, there are avenues to address reliability concerns that are more effective than the use of rules for designated network resources.

without penalty, even if the seller may entail some financial liability for interruption. TAPS states that failure to deliver energy sold in a day-ahead organized market creates an obligation to pay the real-time LMP and potentially other charges, even though the power sale is not generally considered firm. If this potential obligation is interpreted as a liability for purposes of qualifying as a Non-Firm Sale, TAPS concludes that sales into day-ahead organized markets cannot be made from a network resource without first undesignating that resource, which TAPS argues would be unduly burdensome and would discourage network customers from making sales into those markets. TAPS contends that network customers will be reluctant to undesignate their network resources for fear that they would be unable to redesignate them in a timely manner if they are needed to serve native load in real-time.

1014. With regard to the MISO market in particular, TAPS argues that refusing to treat sales into that day-ahead market as Non-Firm Sales would require network customers to undesignate resources to comply with MISO's must offer requirements. TAPS argues that it would be inappropriate to require undesignation of a network resource to sell into the RTO in which the resource is located as well as neighboring RTOs, such as from MISO into PJM. The use of centralized dispatch in these markets, TAPS argues, eliminates any effect temporary resource undesignations and redesignations may have on dispatch or ATC calculations. TAPS contends that the added burden of undesignating and redesignating network resources is therefore pointless in centrally dispatched markets.

1015. E.ON LSE expresses similar concerns, arguing that the definition of Non-Firm Sale in combination with restricted network resource designation policies will result in fewer resources being made available. With regard to the MISO market in particular, E.ON LSE states that the MISO tariff requires that certain day-ahead transactions are made on the condition that the selling generator provide service on-demand. E.ON LSE similarly request that the Commission clarify that day-ahead and real-time sales in MISO and other RTO/ISO markets need not meet the definition of Non-Firm Sales.

Commission Determination

1016. The Commission agrees with NRECA that, under normal circumstances, we would not expect a unit contingent agreement to fall within the definition of a Non-Firm Sale since typically delivery can only be interrupted for the specific reasons identified in the underlying agreement. We also agree with Southern that, under normal circumstances, a system sale that permits curtailment without penalty to serve the seller's native load would fall within the definition of a Non-Firm Sale since the seller would have the right to rely on that capacity in the event it is needed to serve native load, which is the Commission's principal concern in restricting sales from designated network resources to Non-Firm Sales. Whether any particular contract satisfies the definition of Non-Firm Sales, however, must be considered based on the terms and conditions of that contract.

1017. We disagree with TAPS and Washington IOUs that the definition of Non-Firm Sales includes transactions that permit interruption with financial liability, whether make whole or limited to certain penalties. In Order No. 890, the Commission clarified its existing policy prohibiting network customers from making third-party sales from a designated network resource if the third-party power purchase agreement does not allow the seller to interrupt power sales to the third party in order to serve the designated network load.[378] The Commission adopted the definition of Non-Firm Sales to identify more clearly those types of sales that are permitted from designated network resources, explaining that any interruption in service that would create liability on the part of the seller would create conflicting incentives regarding use of the network resource and, therefore, such sale could not be made without first undesignating the resource.[379] The Commission concluded that it would be inappropriate to adopt commenter suggestions to relax the definition of a Non-Firm Sale to include any sale that is not otherwise firm enough to be designated as a network resource.[380]

1018. We appreciate the concerns of E.ON LSE and TAPS regarding the potential effect of this decision on RTO/ISO markets. It does not follow, however, that the *pro forma* OATT must be amended to accommodate the particular market operations of each RTO and ISO. RTOs and ISOs have adopted many variations from the *pro forma* OATT to facilitate development of their markets, with some entirely eliminating the designation/undesignation requirements for network resources. As TAPS explains, centralized dispatch in these markets may very well eliminate any effect that temporary resource undesignations and redesignations have on dispatch or ATC calculations and, therefore, tailoring the rules governing the designation of network resources to each RTO/ISO market could be appropriate.

1019. We note that MISO has adopted the *pro forma* definition of Non-Firm Sales in its compliance filing in response to Order No. 890 and certain members of TAPS have argued in response that adoption of that definition is inconsistent with the operation of the MISO market.[381] The Commission will address those arguments on review of the MISO compliance filing. In the interim, we note that MISO retains significant discretion in how to implement the undesignation requirements for network resources. Pending development of OASIS functionality for electronic submission of undesignations and redesignations, each transmission provider may adopt business practices governing the undesignation and redesignation of network resources. While the Commission referenced the use of telefax or recorded telephone lines to convey this information,[382] the bid-based nature of LMP markets may justify adoption of other procedures. We decline to impose any particular requirements here regarding the designation and undesignation of network resources selling in an RTO/ISO market, as it is more appropriate to leave development of those requirements to each transmission provider, in coordination with its stakeholders as relevant.

d. Commenter Proposals

1020. The Commission declined to adopt various commenter proposals for modifications or additions to the definitions contained in the *pro forma* OATT. For example, the Commission declined to revise the definition of Long-Term Firm Point-to-Point Transmission Service to include service longer than one year, instead of one year or longer. The Commission also rejected commenter requests to adopt proposed definitions for the terms ''source,''

[378] *See* Order No. 890 at P 1539.

[379] *See id.* at P 1692. The Commission's use of the word ''penalty'' in paragraph 1539 of Order No. 890 was not intended to restrict the scope of Non-Firm Sales. As the Commission explained in that paragraph, our concern is that there not be financial incentives that compete with the network resource's obligations to serve its network load. Interruption must therefore be allowed without liability or penalty.

[380] *Id.*

[381] *See* Supplemental Comments of Indiana Municipal Power Agency, Lincoln Electric System, Madison Gas & Electric Company, and Wisconsin Public Power Inc., Docket No. OA08–14–000 (Nov. 6, 2007).

[382] *See* Order No. 890 at P 1543.

''sink,'' ''use,'' and ''transmission peak'' in the *pro forma* OATT.[383]

Requests for Rehearing and Clarification

1021. Ameren argues that the Commission failed to adequately consider its proposal to amend the definition of long-term firm service to include only contracts that are longer than a year. Ameren argues that contracts of only one year in duration should be reflected as a revenue credit and that the current definition of long-term service makes calculation very difficult in the modern RTO/Seams Elimination Cost Allocation (SECA) environment. Ameren contends that the Commission's refusal to modify the definition of long-term service is inconsistent with other decisions in Order No. 890, such as the requirement that the planning redispatch and conditional firm options for long-term firm point-to-point service apply be offered only to customers requesting service of more than a year in duration[384] and the intended planning benefits associated with granting rollover rights only to customers with contracts of five years or longer.

1022. Ameren also challenges the Commission's rejection of an alternative definition for ''transmission peak,'' arguing that the current definition and calculation methodology is unworkable because the data necessary no longer resides with the transmission owner. Ameren further states that the Commission failed to adequately explain rejection of proposed definitions of ''source'' and ''sink'' in section 22.2 of the *pro forma* OATT, and clarification whether the word ''use'' in section 30.8 of the *pro forma* OATT includes load ratio limitations, although Ameren states no arguments in support of that contention.

Commission Determination

1023. The Commission affirms the decision in Order No. 890 to maintain the current definition of Long-Term Firm Point-to-Point Service. The definition is well-established in Commission precedent and, notwithstanding Ameren's arguments to the contrary, consistent with the reforms adopted in Order No. 890.[385] Ameren has failed to justify altering the definition of Long-Term Firm Point-to-Point Service in light of the disruption such a change would cause.

1024. We also decline to amend the *pro forma* OATT to adopt Ameren's proposed definitions of ''transmission peak,'' ''source,'' ''sink,'' and ''use.'' Ameren simply repeats arguments that have previously been rejected. While peak load data ultimately resides with the RTO or ISO in those regions, each transmission owner coordinates this data with the RTO/ISO and, therefore, it is not necessary to alter the definition of transmission peak as suggested by Ameren. The Commission has adequately addressed the definitions of ''source'' and ''sink'' in Order No. 888 and OASIS related proceedings and Ameren fails to state why, in its view, additional clarification is needed. Finally, the Commission has made clear that there are no load ratio limitations on the use of interfaces under section 30.8 of the *pro forma* OATT.[386]

E. Enforcement

1025. The Commission addressed several matters regarding enforcement of the *pro forma* OATT in Order No. 890. Among other things, the Commission concluded that it would revoke an entity's market-based rate authority in response to an OATT violation only upon a finding of a specific factual nexus between the violation and the entity's market-based rate authority.[387] The Commission reasoned that the ''nexus condition'' is required in order to ensure that the Commission's actions are not arbitrary or capricious or based on an inadequate factual record. The Commission noted that in such situations it would have the burden to show a factual nexus and did not assign a burden on the violator to show a lack of nexus.

1026. The Commission disagreed that a finding of a ''serious'' or ''material'' violation of the OATT alone would be sufficient to justify revocation of an entity's market-based rate authority. The Commission concluded that the nexus condition requires a finding both that a substantial OATT violation has occurred and that the violation either related to the exercise of the violator's market-based rate authority or violated a specific condition of that authority.[388] The Commission emphasized, moreover, that it has discretion to fashion further sanctions, such as civil penalties or modification of a violator's market-based rate authority, for OATT violations that relate to the violator's market-based rate authority where a factual nexus justification was not found to justify revocation of that authority.

1027. The Commission also created a rebuttable presumption that all of the transmission provider's affiliates should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation.[389] The Commission stated that it would allow an affiliate of a transmission provider to retain its market-based rate authority in a market area if the affiliate overcomes the rebuttable presumption with respect to that market area. To afford due process to a transmission provider's affiliates and to ensure that revocation of market-based rate authority in a particular market for the transmission provider and all of its affiliates is adequately based upon record evidence and not arbitrary or capricious, the Commission provided that each such affiliate will be allowed to make a showing that it should retain its market-based rate authority or that enforcement action against it should be less severe than revocation.

1028. The Commission explained that whether an affiliate has overcome the rebuttable presumption will depend on an analysis of specific facts in the record. Relevant facts would include, but are not limited to, whether: (1) The transmission provider and the affiliate were under the same control; (2) the affiliate knew of, participated in or was an accomplice to the OATT violation; (3) the affiliate assisted the transmission provider in exercising market power; or (4) the affiliate benefited from the violation.[390]

Requests for Rehearing and Clarification

1029. NRECA argues that it is unclear what would constitute a sufficient factual nexus between an OATT violation and revocation of the violator's market-based rate authority. NRECA suggests that the Commission instead adopt the standard advocated by APPA in its NOPR comments, which would require revocation of the affiliate's market-based rate authority when there is any material violation of the transmission provider's OATT that denies a customer access to just, reasonable, nondiscriminatory, and comparable transmission service. If the Commission retains the nexus

[383] Powerex's request for rehearing of the Commission's decision not to modify the definition of System Impact Study to exclude short-term service requests is discussed in section III.D.4.a.(6) above.

[384] *Citing* Order No. 890 at P 978.

[385] The Commission clarifies in section III.D.1 our intent that the conditional firm and planning redispatch options apply to all long-term firm point-to-point requests for service, *i.e.*, service of one year or longer.

[386] *See* Order No. 888 at 31,753–54; Order No. 888–A at 30,304–5; *see also Sierra Pacific Power Co.*, 81 FERC ¶ 61,136 at 61,139–40 (1997); *New England Power Pool*, 83 FERC ¶ 61,045 at 61,248 (1998).

[387] Order No. 890 at P 1743.

[388] *Id.* at P 1744.

[389] *Id.* at P 1747.

[390] *Id.* at P 1748.

requirement as formulated in Order No. 890, NRECA asks that the Commission provide an illustrative list of what types of violations could constitute a sufficient nexus between an OATT violation and an entity's market-based rate authority. NRECA urges the Commission to specifically identify failure to comply with the planning requirements of Order No. 890 as satisfying the nexus requirement.

1030. TDU Systems argue that the nexus requirement does not pay adequate attention to the basic nature and purpose of the market-based rate authorization and, in their view, the critical question is whether the OATT violation is indicative of conditions in the market which are significantly different from those upon which the market-based rate authorization was premised. TDU Systems argue that a transmission provider's violation of a material term of its OATT should serve as *prima facie* evidence that the structures presumed to cabin the exercise of monopoly power may not be adequate. Even if the transmission provider has not violated its OATT explicitly in connection with the market-based rate authorization, TDU Systems contend that the violation may nonetheless promote conditions in which the transmission provider could gain an advantage in future transactions. TDU Systems state particular concern that failure to comply with the planning obligations of Order No. 890 may not be associated with any specific exercise of market-based rate authority, yet could foster conditions inconsistent with the premises of unconstrained and competitive markets.

1031. EEI argues that, since there is no rebuttable presumption with respect to a transmission provider's OATT violation and its potential loss of market-based rate authority, there should be no rebuttable presumption regarding the market-based rate authority of the transmission provider's affiliates. EEI contends that the Commission's Code of Conduct actually supports a presumption that a transmission provider's OATT violation does *not* have any relation to the activities of the marketing affiliate since, absent evidence to the contrary, the utility and its energy affiliates should be presumed to be obeying the Commission's separation of function requirements. EEI further argues that the Commission's reference to allegations that transmission providers have engaged in transactions with affiliates does not justify adoption of a rebuttable presumption in instances in which there are no transactions with affiliates that violated the OATT. EEI therefore asks the Commission to grant rehearing and hold that the rebuttable presumption applies only if there is a specific factual nexus between the activities of the marketing affiliate and the OATT violation.

1032. Ameren similarly argues that most integrated utility companies that have market-based rate authority have separated their marketing activities into ''regulated'' traditional utility functions and ''non-regulated'' power marketing functions and have further separated their transmission and merchant energy functions. Ameren states that these utilities' codes of conduct and the Commission's Standards of Conduct severely restrict the sharing of information within an integrated utility company or the possible benefit to affiliates from an OATT violation. Ameren argues that the presumption adopted by the Commission unreasonably assumes a lack of compliance with these obligations and unfairly shifts the burden to the affiliate to show that it has not engaged in bad acts.

1033. Ameren contends that a decision by the Commission to revoke a transmission provider's market-based rate authority would indicate only that the Commission has determined that sanction to be appropriate in light of the transmission provider's actions. In Ameren's view, there is no reason or basis to similarly sanction the transmission provider's affiliate in the absence of a showing that the affiliate participated in, or benefited from, the transmission provider's improper behavior. Ameren also argues that the presumption is inconsistent with the Commission's decision in Order No. 890 to allow non-offending affiliates of the transmission provider to share in the distribution of operating penalties. Finally, Ameren argues that revoking the market-based rate authority of a utility because of the actions of an affiliated transmission provider would unfairly harm the traditional utility affiliate as well as its bundled customers since many traditional utilities engage in sales at market-based rates to reduce their overall cost of power.

1034. Southern asks that the Commission confirm and clarify that the rebuttable presumption does not shift the ultimate burden of proof to the transmission provider or its affiliates, but rather places a burden of going forward on the affiliates, with the ultimate burden remaining with the Commission or other proponents of a revocation sanction. Southern suggests that the presentation of evidence that rebuts the presumption should result in the burden of proof reverting back to the Commission or the proponent of revocation.

1035. Southern also requests clarification of the relevant facts to be considered by the Commission in determining whether a sanction less severe than revocation of market-based rate authority may be appropriate for an affiliate. Southern notes that the first relevant fact noted by the Commission in paragraph 1748 of Order No. 890 is whether the transmission provider and the affiliate were under ''the same control.'' Southern questions what the Commission meant by that language since a transmission provider is by definition under the same corporate control as an affiliate.

Commission Determination

1036. The Commission denies rehearing of the decision in Order No. 890 to require a factual nexus between a substantial OATT violation and the entity's market-based rate authority to justify revocation of that authority. As the Commission explained in Order No. 890, the ''nexus condition'' is required in order to ensure that our actions are not arbitrary or capricious or based on an inadequate factual record. We disagree with NRECA and TDU Systems that any material OATT violation should justify revocation of the entity's market-based rate authority since the violation may have no relation to the market-based rate authority. In such circumstances, the Commission will consider such other sanctions as may be appropriate. We also decline to provide an illustrative list of examples that would constitute a sufficient nexus between an entity's market-based rate authority and an OATT violation. The factual circumstances involved in a claimed violation will be unique to the company and, therefore, any such list would be incomplete. This is especially true in light of continually developing market conditions. We continue to believe that the determination of what would be a sufficient factual nexus between an OATT violation and revocation of the violator's market-based rate authority is best left to case-by-case consideration.

1037. With regard to the transmission provider's planning obligations, violations of the planning-related requirements of the *pro forma* OATT may or may not have a sufficient factual nexus with the transmission provider's market-based rate authority. A case-by-case analysis will be necessary to determine if the violation justifies revocation of the transmission provider's market-based rate authority. While we agree with TDU Systems that a transmission provider's OATT violations that are not explicitly connected with its market-based rate authorization may nonetheless promote conditions in which the violator could gain an advantage in future transactions, we note that this is the precise result that we seek to avoid with this enforcement provision. Therefore, we will apply the mechanisms adopted in Order No. 890 to aid us in determining, on a case-by-case basis if a particular violation promotes conditions that will put that company at a future advantage vis-à-vis its market-based rate authority.

1038. We also decline to adopt TDU Systems' suggestion that we consider whether the OATT violation is indicative of conditions in the market that are significantly different from those upon which the market-based rate authorization was premised. When the revocation of market-based rate authority is being considered, we will distinguish between those violations resulting from a change in market conditions upon which the market-based rate authority was granted (and which are likely outside of the company's control) versus a clear violation related to the company's market-based rate authority. It may be most appropriate to address those violations resulting from changes in market conditions with an amendment to the affected company's OATT or market-based rate tariff.

1039. We also affirm the adoption of a rebuttable presumption that all of the transmission provider's affiliates should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation.[391] While we agree that, absent evidence to the contrary, the transmission provider and its affiliates should be presumed to be obeying the Commission's separation of function requirements and Affiliate Restrictions, we disagree that this undermines the rebuttable presumption adopted in Order No. 890. If a violation has occurred that justifies revocation of the entity's market-based rate authority, the violation must have related to that market-based rate authority. Assuming that the Standards of Conduct and Affiliate Restrictions were followed, the finding of a nexus between the violation and the entity's market-based rate authority demonstrates that the Standards of Conduct or Affiliate Restrictions did not preclude the violation. An OATT violation by a transmission provider that merits revocation of the transmission provider's market-based rate authority will, at a minimum, raise the question whether the transmission provider's affiliates continue to qualify for market-based rates under the standards established by the Commission.

1040. Applying this rebuttable presumption to the transmission provider's affiliates is not, as suggested by Ameren, inconsistent with the Commission's decision in Order No. 890 to allow non-offending affiliates of the transmission provider to share in the distribution of unreserved use penalties.[392] Unreserved use penalties are a mechanism used to redress administrative violations of the OATT and can be assessed on any transmission customer. It is therefore appropriate to distribute those penalties to all non-offending customers, whether or not affiliated with the transmission provider. Unreserved use penalties do not rise to the level of the sanction of revocation of market-based rate authority, to which the presumption applies.

1041. We also disagree that there must be a showing of benefit by the affiliate in order to revoke its market-based rate authority or that potential economic harm to the transmission provider's bundled customers categorically justifies an affiliate to continue making sales at market-based rates to reduce the company's overall cost of power, even if the affiliate should otherwise lose its market-based rate authority. It is possible that a transmission provider could violate its OATT with an intent to advantage an affiliated marketer that, in turn, attempts to take advantage of the violation in the market but is unsuccessful because of market conditions. Alternatively, the affiliated marketer could be successful, gaining an unfair advantage due to the transmission provider's OATT violation, but thereby earning revenue that ultimately serves to lower the cost of supplies for the company's bundled customers. In either of these circumstances, it could be appropriate to revoke or modify the market-based rate authority of the affiliate. Therefore, the facts of each violation must be considered in order to determine if revocation of market-based rate authority is an appropriate sanction.

1042. With regard to Southern's request for clarification concerning the burden of proof to show that an affiliate should lose its market-based rate authority, we confirm that the ultimate burden remains with the Commission. The presumption does not constitute a definitive finding that the affiliate's market-based rate authority should be revoked and, thus, the affiliate has an opportunity to demonstrate that revocation would not be appropriate under the facts and circumstances at issue.[393] The rebuttable presumption thus satisfies the Commission's burden of going forward and shifts to the affiliate the burden of presenting evidence rebutting the presumption. The ultimate burden of proof remains with the Commission throughout these proceedings, and it must base any finding on a review of the factual record.[394]

1043. We clarify in response to Southern that the reference to whether "the transmission provider and the affiliate were under the same control" in paragraph 1748 of Order No. 890 is intended to reflect that the Commission will consider whether the affiliation between the transmission provider and the affiliate is sufficient to give either or a common parent control over both entities.

IV. Information Collection Statement

1044. The Office of Management and Budget (OMB) regulations require that OMB approve certain information collection requirements imposed by an agency.[395] The revisions to the information collection requirements for transmission providers adopted in Order No. 890 were approved under OMB Control Nos. 1902–0233. This order further revises these requirements in order to more clearly state the obligations imposed in Order No. 890, but does not substantively alter those requirements. OMB approval of this order is therefore unnecessary. However, the Commission will send a copy of this order to OMB for informational purposes only.

V. Document Availability

1045. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First

[391] *Accord* Order No. 697 at P 424–427.

[392] Although Ameren refers more generally to operational penalties, only unreserved use penalties may be distributed to affiliated customers. Late study penalties are to be distributed only to non-affiliated transmission customers. *See* Order No. 890 at P 1351.

[393] The use of shifting burdens of proof is consistent with Commission practice in other areas. *See, e.g., AEP Power Mktg, Inc.,* 108 FERC ¶ 61,026 (2004); *Southern Companies Energy Mktg, Inc.,* 111 FERC ¶ 61,144 (2005).

[394] *See* Order No. 890 at P 1743–48.

[395] 5 CFR 1320.

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VI. Effective Date and Congressional Notification

1048. Changes to Order No. 890 adopted in this order on rehearing will become effective March 17, 2008.

List of Subjects in 18 CFR Part 37

Conflict on interests, Electric power rates, Electric power plants, Reporting and recordkeeping requirements.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

■ In consideration of the foregoing, the Commission amends part 37, Chapter I, Title 18 of the *Code of Federal Regulations*, as follows:

PART 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEMS

■ 1. The authority citation for part 37 continues to read as follows:

Authority: 16 U.S.C. 791–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. Amend § 37.6 as follows:
■ a. Paragraph (b)(3)(iv) is revised.
■ b. Paragraph (h)(1) introductory text is revised.
■ c. Paragraph (h)(3) introductory text is revised.
■ d. Paragraph (i) is revised.

§ 37.6 Information to be posted on the OASIS.

* * * * *

(b) * * *

(3) * * *

(iv) *Daily load.* The Transmission Provider must post on a daily basis, its load forecast, including underlying assumptions, and actual daily peak load for the prior day.

* * * * *

(h) *Posting information summarizing the time to complete transmission service request studies.* (1) For each calendar quarter, the Responsible Party must post the set of measures detailed in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section related to the Responsible Party's processing of transmission service request system impact studies and facilities studies. The Responsible Party must calculate and post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section for requests for short-term firm point-to-point transmission service, requests for long-term firm point-to-point transmission service, and requests to designate a new network resource or network load. When calculating the measures in paragraph (h)(1)(i) through paragraph (h)(1)(iv) of this section, the Responsible Party may aggregate requests for short-term firm point-to-point service and requests for long-term firm point-to-point service, but must calculate and post measures separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates. The Responsible Party is required to include in the calculations of the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section all studies the Responsible Party conducts of transmission service requests on another Transmission Provider's OASIS.

* * * * *

(3) The Responsible Party will be required to post on OASIS the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section in the event the Responsible Party, for two consecutive calendar quarters, completes more than twenty (20) percent of the studies associated with requests for transmission service from entities that are not Affiliates of the Responsible Party more than sixty (60) days after the Responsible Party delivers the appropriate study agreement. The Responsible Party will have to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section until it processes at least ninety (90) percent of all studies within 60 days after it has received the appropriate executed study agreement. For the purposes of calculating the percent of studies completed more than sixty (60) days after the Responsible Party delivers the appropriate study agreement, the Responsible Party should aggregate all system impact studies and facilities studies that it completes during the reporting quarter.

* * * * *

(i) *Posting data related to grants and denials of service.* The Responsible Party is required to post data each month listing, by path or flowgate, the number of transmission service requests that have been accepted and the number of transmission service requests that have been denied during the prior month. This posting must distinguish between the length of the service request (*e.g.*, short-term or long-term requests) and between the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The posted data must show:

(1) The number of non-Affiliate requests for transmission service that have been rejected,

(2) The total number of non-Affiliate requests for transmission service that have been made,

(3) The number of Affiliate requests for transmission service, including requests by the transmission provider's merchant function to designate a network resource or to procure secondary network service, that have been rejected, and

(4) The total number of Affiliate requests for transmission service, including requests by the transmission provider's merchant function to designate, or terminate the designation of, a network resource or to procure secondary network service, that have been made.

* * * * *

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

APPENDIX A TO THE PREAMBLE: PETITIONER ACRONYMS

Abbreviation	Petitioner names
Alcoa	Alcoa Inc. and Alcoa Power Generating Inc.
Ameren	Ameren Services Company.
AMP-Ohio	American Municipal Power-Ohio, Inc.
APPA	American Public Power Association.
AWEA	American Wind Energy Association.

APPENDIX A TO THE PREAMBLE: PETITIONER ACRONYMS—Continued

Abbreviation	Petitioner names
Areva	Areva T&D.
APS	Arizona Public Service Company.
ATCLLC	American Transmission Company LLC.
Barclays	Barclays Bank PLC, Credit Suisse Energy LLC, J. Aron & Co., and Morgan Stanley Capital Group Inc.
Bonneville	Bonneville Power Administration.
Constellation	Constellation Energy Group, Inc.
Duke	Duke Energy Corp.
Dynegy	Dynegy Power Marketing, Inc., Entegra Power Group LLC, LS Power Associates.
E.ON LSE	E.ON Load Serving Entity.
E.ON U.S.	E.ON U.S. LLC.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Sam Rayburn Generation and Electric Cooperative, Inc. and Tex-La Electric Cooperative of Texas, Inc.
EEI	Edison Electric Institute.
EPSA	Electric Power Supply Association.
Entergy	Entergy Services, Inc.
Financial Service Joint Requestors	Barclays Bank PLC, Credit Suisse Energy LLC, J. Aron & Company, and Morgan Stanley Capital Group Inc.
FMPA	Florida Municipal Power Agency and Midwest Municipal Transmission Group.
Florida Power	Florida Power & Light Co.
Great Northern	Great Northern Power Development, L.P.
Idaho Power	Idaho Power Co.
Indicated Commenters	Dynegy Power Marketing, Inc., Entegra Power Group LLC, and LS Power Associates, L.P.
ISO/RTO Council	ISO/RTO Council.
Mark Lively	Mark B. Lively.
MidAmerican	MidAmerican Energy Company and PacifiCorp.
MISO	Midwest Independent Transmission System Operator, Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
National Grid	National Grid USA.
NRECA	National Rural Electric Cooperative Association.
NYISO	New York Independent System Operator.
New York Transmission Owners	Central Hudson Gas & Elec. Corp., Consolidated Edison Co. of New York, Inc., LIPA, New York Power Authority, New York State Electric & Gas Corp., Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corp.
NCEMC	North Carolina Electric Membership Corporation.
NCPA	Northern California Power Agency.
NorthWestern	NorthWestern Corporation.
Old Dominion	Old Dominion Electric Cooperative.
Pacific Northwest Parties	Avista Corp., Bonneville Power Administration, PacifiCorp, PNGC Power, Portland General Electric Company, and Puget Sound Energy, Inc.
PJM	PJM Interconnection, LLC.
Powerex	Powerex Corp.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Co. d/b/a Progress Energy Carolinas, Inc. and Florida Power Corp., d/b/a Progress Energy Florida, Inc.).
PNM	Public Service Company of New Mexico.
PSEG	Public Service Electric and Gas Company; PSEG Power LLC; and PSEC Energy Resources & Trade LLC (PSEG Companies).
REPIO	Renewable Energy and Public Interest Organizations (The Project for Sustainable FERC Energy Policy, Environmental Law & Policy Center, Illinois Citizens Utility Board, Natural Resources Defense Council, Northwest Energy Coalition, Pace Energy Project, Renewable Northwest Project, West Wind Wires, and Wind on Wires.
Sempra Global	Sempra Global.
South Carolina E&G	South Carolina Electric & Gas Company.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern	Southern Company Services, Inc.
Steel Manufacturers Association	Steel Manufacturers Association.
Tenaska	Tenaska Power Services, Co.
TranServ	TranServ International, Inc.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
Unitil	Unitil Power Corp., Unitil Energy Systems, Inc. and Fitchburg Gas and Elec. Light Co.
Washington IOUs	Avista Corp. and Puget Sound Energy, Inc.
Williams	Williams Power Company, Inc.
Wisconsin Electric	Wisconsin Electric Power Company.
WSPP	Western Systems Power Pool, Inc.
Xcel	Xcel Energy Services, Inc.

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

APPENDIX B TO THE PREAMBLE: POST-TECHNICAL CONFERENCE COMMENTER ACRONYMS

Abbreviation	Commenter names
Alabama Municipal	Alabama Municipal Electric Authority.
APS and EEI	Arizona Public Service Company and Edison Electric Institute.
Barrick Goldstrike Mines	Barrick Goldstrike Mines Inc. and Barrick Turquoise Ridge Inc.
Bonneville	Bonneville Power Administration.
Duke Energy Carolinas	Duke Energy Carolinas, LLC.
Duke and EEI	Duke Energy Corp. and Edison Electric Institute.
EPSA	Electric Power Supply Association.
Great Lakes	Great Lakes Utilities.
Hoosier	Hoosier Energy Rural Electric Cooperative, Inc.
Kansas Power Pool	Kansas Power Pool.
MISO	Midwest Independent Transmission System Operator, Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
Pacific Northwest IOUs	Avista Corp., Portland General Electric Company, and Puget Sound Energy, Inc.
Powerex	Powerex Corp.
PNGC Power	Pacific Northwest Generating Cooperative, Inc.
PPC	Public Power Council.
PPL Parties	PPL EnergyPlus, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Edgewood Energy, LLC, PPL Great Works, LLC, PPL Holtwood, LLC, PPL Maine, LLC, PPL Martins Creek, LLC, PPL Montana, LLC, PPL Montour, LLC, PPL Shoreham Energy, LLC, PPL Susquehanna, LLC, PPL University Park, LLC, and PPL Wallingford Energy LLC.
Reliant	Reliant Energy, Inc.
SCE and SDG&E	Southern California Edison Co. and San Diego Gas & Electric Co.
South Carolina E&G	South Carolina Electric & Gas Company.
Southern	Southern Company Services, Inc.
Southwestern Utilities	Arizona Public Service Company, El Paso Electric Company, Nevada Power Company and Sierra-Pacific Power Company, Public Service Company of New Mexico, Salt River Project, Tucson Electric Power Company, and UNS Electric Inc.
TAPS and APPA	Transmission Access Policy Study Group and the American Public Power Association.
TDU Systems	Transmission Dependent Utilities Systems.
WSPP	Western Systems Power Pool, Inc.

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

Appendix C to the Preamble: RM05–17–001, –002 & RM05–25–001, –002 (Issued)

Pro Forma Open Access Transmission Tariff

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I. Common Service Provisions

1 Definitions

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.4 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 Commission

The Federal Energy Regulatory Commission.

1.6 Completed Application

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
2. Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
4. Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.12 Eligible Customer

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.13 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.15 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.16 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.17 Load Ratio Share

Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.

1.18 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.20 Native Load Customers

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff.

1.23 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a Commission-approved reserve sharing program.

1.27 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.30 Open Access Same-Time Information System (OASIS)

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.31 Part I

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Parties

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.35 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.36 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.38 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.39 Pre-Confirmed Application

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.40 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.41 Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.42 Reserved Capacity

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.43 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.44 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.45 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.46 System Condition

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.47 System Impact Study

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.50 Transmission Provider

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.51 Transmission Provider's Monthly Transmission System Peak

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.53 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority for Existing Firm Service Customers

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to the longest competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to [the date of the Transmission Provider's filing adopting the reformed rollover language herein in compliance with Order No. 890] or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after [the date of the Transmission Provider's filing adopting the reformed rollover language herein in compliance with Order No. 890]; provided that, the one-year notice requirement shall apply to such service agreements with five years or more left in their terms as of the [date of the Transmission Provider's filing adopting the reformed rollover language herein in compliance with Order No. 890].

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is required to provide (or offer to arrange with the local Control Area Operator as discussed below), to the extent it is physically feasible to do so from its resources or from resources available to it, Generator Imbalance Service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer using Transmission Service to deliver energy from a generator located within the Transmission Provider's Control Area is required to acquire Generator Imbalance Service, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5, 6 and 9) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) Any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control From Generation or Other Sources Service

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service

Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service

Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service

Where applicable the rates and/or methodology are described in Schedule 9.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 C.F.R. § 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on OASIS and its public Web site an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS and on its public Web site an electronic link to the NAESB Web site where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also post on OASIS and its public Web site an electronic link to a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are not included in this tariff. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds

This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the transmission-owning members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the

Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

The Transmission Provider will specify its Creditworthiness procedures in Attachment L.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

2. One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Federal Power Act

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-To-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has requested service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction or reservation. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration and, as relevant, pre-confirmation status (pre-confirmed, confirmed, or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or reservation.

(iii) If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after March 17, 2008 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm

Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved.

13.8 Scheduling of Firm Point-To-Point Transmission Service

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after March 17, 2008 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service

Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-To-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation To Provide Transmission Service That Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission

Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service

The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof within 15 days of notifying the Transmission Provider it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transfer Capability

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service. [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these options. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including an estimate of the cost of redispatch, (3) conditional curtailment options (when requested by an Eligible Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur, and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Penalties for Failure To Meet Study Deadlines

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

20 Procedures if the Transmission Provider Is Unable To Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications on a Non-Firm Basis

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement (''Secondary Receipt and Delivery Points''), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification on a Firm Basis

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion; provided that, for service prior to October 1, 2010, compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Transmission Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. The Transmission Provider shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this

Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-to-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

29 Initiating Service

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the

Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

• Unit size and amount of capacity from that unit to be designated as Network Resource
• VAR capability (both leading and lagging) of all generators
• Operating restrictions
—Any periods of restricted operations throughout the year
—Maintenance schedules
—Minimum loading level of unit
—Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons
• Approximate variable generating cost ($/MWH) for redispatch computations
• Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

• Identification of the Network Resource as an off-system resource
• Amount of power to which the customer has rights
• Identification of the control area from which the power will originate
• Delivery point(s) to the Transmission Provider's Transmission System
• Transmission arrangements on the external transmission system(s)
• Operating restrictions, if any
—Any periods of restricted operations throughout the year
—Maintenance schedules
—Minimum loading level of unit
—Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons
• Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

• Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
• Operating restrictions needed for reliability
• Operating guides employed by system operators
• Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
• Location of Network Resources described in subsection (v) above
• 10 year projection of system expansions or upgrades
• Transmission System maps that include any proposed expansions or upgrades
• Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) The Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements To Be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) The Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a Commission-approved reserve sharing program. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's

Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With the Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the [the effective date of a Final Rule in RM05–25–000], the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected With the Transmission Provider

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (*e.g.* the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service

Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including, to the extent possible, an estimate of the cost of redispatch, (3) available options for installation of automatic devices to curtail service (when requested by an Eligible Customer), and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Penalties for Failure To Meet Study Deadlines

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

33 Load Shedding and Curtailments

33.1 Procedures

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

33.5 Allocation of Curtailments

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct

Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load

The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation Under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 CFR 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Schedule 1—Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2—Reactive Supply and Voltage Control From Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3—Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4—Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule or a penalty for hourly generator imbalances under Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) Deviations within $+/-1.5$ percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than $+/-1.5$ percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than $+/-7.5$ percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, *i.e.*, to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Schedule 5—Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6—Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7—Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $____/KW of Reserved Capacity per year.

(2) Monthly delivery: $____/KW of Reserved Capacity per month.

(3) Weekly delivery: $____/KW of Reserved Capacity per week.

(4) Daily delivery: $____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

(6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

Schedule 8—Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $____/KW of Reserved Capacity per month.

(2) Weekly delivery: $____/KW of Reserved Capacity per week.

(3) Daily delivery: $____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $____/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

(6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

Schedule 9—Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or a penalty for hourly energy imbalances under Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/−1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/−1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/−7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

1. Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental and decremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

2. For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, *i.e.*, to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Attachment A—Form of Service Agreement For Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ (''Transmission Customer'').

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

____

Name

____

Title

____

Date

Transmission Customer:

By:

____

Name

____

Title

____

Date

Specifications for Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ____________

Start Date: ____________

Termination Date: ____________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates. ____

____

3.0 Point(s) of Receipt: ____________

Delivering Party: ____________

4.0 Point(s) of Delivery: ____________

Receiving Party: ____________

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): ____________

6.0 Designation of party(ies) subject to reciprocal service obligation: ____________

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service: __

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ____________

____

8.2 System Impact and/or Facilities Study Charge(s): ____________

____

____

8.3 Direct Assignment Facilities Charge: ____________

____

8.4 Ancillary Services Charges: ______

____

____

____

____

____

____

Attachment A–1—Form of Service Agreement for the Resale, Reassignment, or Transfer of Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Assignee:

______

______

______

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

______

Name

______

Title

______

Date

Assignee:

By:

______

Name

______

Title

______

Date

Specifications for the Resale, Reassignment, or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ______

Start Date: ______

Termination Date: ______

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates. ______

______

3.0 Point(s) of Receipt: ______

Delivering Party: ______

4.0 Point(s) of Delivery: ______

Receiving Party: ______

5.0 Maximum amount of reassigned capacity: ______

6.0 Designation of party(ies) subject to reciprocal service obligation: ______

______

______

______

7.0 Name(s) of any Intervening Systems providing transmission service: ______

______

______

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ______

8.2 System Impact and/or Facilities Study Charge(s): ______

8.3 Direct Assignment Facilities Charge: ______

8.4 Ancillary Services Charges: ______

______

______

______

______

______

______

9.0 Name of Reseller of the reassigned transmission capacity:

______

Attachment B—Form of Service Agreement for Non-Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

______

______

______

Transmission Customer:

______

______

______

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

______

Name

______

Title

______

Date

Transmission Customer:

By:

______

Name

______

Title

______

Date

Attachment C—Methodology To Assess Available Transfer Capability

The Transmission Provider must include, at a minimum, the following information concerning its ATC calculation methodology:

(1) A detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon);

(2) A process flow diagram that illustrates the various steps through which ATC/AFC is calculated; and

(3) A detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons.

(a) For TTC, a Transmission Provider shall: (i) Explain its definition of TTC; (ii) explain its TTC calculation methodology; (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(b) For ETC, a transmission provider shall explain: (i) Its definition of ETC; (ii) the calculation methodology used to determine the transmission capacity to be set aside for native load (including network load), and non-OATT customers (including, if applicable, an explanation of assumptions on the selection of generators that are modeled in service); (iii) how point-to-point transmission service requests are incorporated; (iv) how rollover rights are accounted for; (v) its processes for ensuring that non-firm capacity is released properly (*e.g.*, when real-time schedules replace the associated transmission service requests in its real-time calculations); and (vi) describe the step-by-step modeling study methodology and criteria for adding or eliminating flowgates (permanent and temporary).

(c) If a Transmission Provider uses an AFC methodology to calculate ATC, it shall: (i) Explain its definition of AFC; (ii) explain its AFC calculation methodology; (iii) explain its process for converting AFC into ATC for OASIS posting; (iv) list the databases used in its AFC assessments; and (v) explain the assumptions used in its AFC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(d) For TRM, a Transmission Provider shall explain: (i) Its definition of TRM; (ii) its TRM calculation methodology (*e.g.*, its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (iii) the databases used in its TRM assessments; (iv) the conditions under which the transmission provider uses TRM. A Transmission Provider that does not set aside transfer capability for TRM must so state.

(e) For CBM, the Transmission Provider shall include a specific and self-contained narrative explanation of its CBM practice, including: (i) An identification of the entity who performs the resource adequacy analysis for CBM determination; (ii) the methodology used to perform generation reliability assessments (*e.g.*, probabilistic or deterministic); (iii) an explanation of whether the assessment method reflects a specific regional practice; (iv) the assumptions used in this assessment; and (v) the basis for the selection of paths on which CBM is set aside.

(f) In addition, for CBM, a Transmission Provider shall: (i) Explain its definition of CBM; (ii) list the databases used in its CBM calculations; and (iii) demonstrate that there is no double-counting of contingency outages when performing CBM, TTC, and TRM calculations.

(g) The Transmission Provider shall explain its procedures for allowing the use of CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). If the Transmission Provider's practice is not to set aside transfer capability for CBM, it shall so state.

Attachment D—Methodology for Completing a System Impact Study

To be filed by the Transmission Provider.

Attachment E—Index of Point-To-Point Transmission Service Customers

Customer Date of Service Agreement

Attachment F—Service Agreement for Network Integration Transmission Service

To be filed by the Transmission Provider.

Attachment G—Network Operating Agreement

To be filed by the Transmission Provider.

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be ______.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Attachment I—Index of Network Integration Transmission Service Customers

Customer Date of Service Agreement

Attachment J—Procedures for Addressing Parallel Flows

To be filed by the Transmission Provider.

Attachment K—Transmission Planning Process

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05–25–000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05–25–000.

The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers and neighboring transmission providers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop transmission plans;

(iv) The method of disclosure of criteria, assumptions and data underlying transmission system plans;

(v) The obligations of and methods for customers to submit data to the transmission provider;

(vi) The dispute resolution process;

(vii) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and

(viii) The relevant cost allocation procedures or principles.

Attachment L—Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit.

The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:

(1) A summary of the procedure for determining the level of secured and unsecured credit;

(2) A list of the acceptable types of collateral/security;

(3) A procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;

(4) A procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;

(5) A reasonable opportunity to contest determinations of credit levels or collateral requirements; and

(6) A reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

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