UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Preventing Undue Discrimination and Preference in Transmission Services		Docket No. RM05-25-000

**REPLY COMMENTS OF THE
TRANSMISSION ACCESS POLICY STUDY GROUP**

EXECUTIVE SUMMARY

The Transmission Access Policy Study Group ("TAPS") hereby responds to the following issues raised in the comments filed in this proceeding:[1]

? The Commission should not perform radical surgery on the Order 888[2] OATT, but should retain network service, while adopting the changes proposed in TAPS' Initial Comments to provide the comparable service and access to the competitive market that Order 888 intended, and which Congress recently reinforced.

? The Commission should dismiss arguments seeking to maintain punitive energy imbalance charges, and end this discrimination that can only be remedied by modifying the OATT.

? The Commission should not adopt the grossly exaggerated interpretations of Section 217, the Native Load Service Obligation provision of the Energy Policy Act of 2005 ("EPAct 2005"),[3] proposed by a number of commenters.

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[1] TAPS has not attempted to be comp rehensive in addressing the myriad comments submitted and issues raised. Especially given the comprehensiveness of our November 22, 2005 Initial Comments in this docket ("TAPS Initial Comments"), we have attempted to be more surgical in reply, resting on our Initial Comments to rebut many of the arguments made by others.

[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 Fed. Reg. 21,539, *reprinted in* [1991-1996 Regs. Preambles] FERC Stat. & Regs. ¶ 31,036, *clarified*, 76 F.E.R.C. ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), *reprinted in* [1996-2000 Regs. Preambles] FERC. Stat. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 F.E.R.C. ¶ 61,248 (1997), *aff'd in part and remanded in part sub nom. 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), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998).

[3] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1233, 119 Stat. 594 (2005), § 1233.

? The Commission should reject calls to lift its ban on "and" pricing for network customers.

? The Commission should require joint planning, notwithstanding the opposition of the Edison Electric Institute ("EEI") and should reject EEI's proposal to water down the OATT's transmission planning obligation. TAPS provides specific criteria and procedures that the Commission can use to put in place a joint transmission planning process, and in Appendix A suggests specific tariff language changes to implement its suggestions.

I. THE COMMISSION SHOULD MAINTAIN NETWORK SERVICE BUT UNDERTAKE THE "TARIFF TINKERING"[4] PROPOSED IN TAPS' INITIAL COMMENTS

What is striking about the comments filed in this proceeding is the absence of industry support for major structural changes to the OATT. For example, even the Electric Power Supply Association ("EPSA") (a long-time proponent of a *pro forma* tariff with a single type of transmission service) does not suggest combining network and point-to-point service, stating:[5]

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[4] *See* Bruce W. Radford, *Tariff Tinkering*, Public Utilities Fortnightly, Jan. 2006, at 27-28.

[5] EPSA Comments at 49. Nevada Power Co. and Sierra Pacific Power Co. ("The Nevada Companies") advocate mandatory network contract demand ("NCD") service in lieu of existing network service (at 18, 21, 24, 55), but based on TAPS' non-scientific sampling of comments, it appears that they are alone. Most commenters who addressed this issue focused on whether the Commission should require transmission providers to offer NCD service as an option in addition to—and certainly not as a replacement for—existing network service. Beyond being an apparent outlier, the Nevada Companies' proposal is antithetical to the concept of NCD service that the Commission apparently had in mind in its query. The Nevada Companies candidly admit that the motivation behind their proposal is to avoid the pesky problem of designating network resources to meet their native load as they are required to do under the *pro forma* OATT's network service provisions. *Id.* at 21-22. What they appear not to recognize is that the NCD service offered by Florida Power Corporation—to which the Commission pointed in its question—clearly requires designation of network resources, which are subject to the same limitations as in the "standard" network section of the OATT, *i.e.*, network resources must be owned or leased generation or purchases under an "executed contract." The sort of NCD provisions the Commission seems to have had in mind would *not* allow the Nevada Companies to bottle up transmission capacity based on amorphous plans to acquire resources at a later date to meet expected load growth. In its comments, Florida Power & Light Company identifies problems such a version of NCD service may present. Although TAPS does not endorse everything in that discussion, we share the general concern regarding effects of such a form of NCD service (*i.e.*, that allows evasion of network resource designation requirements) on available transmission capacity, particularly into load pockets (such as the control areas of the Nevada Companies).

> [T]he Commission absolutely should not modify the basic requirement that an OATT offer firm and non-firm point-to-point transmission service and firm network transmission service.

The few comments suggesting more radical changes propose no mechanism to achieve those changes, even assuming they were advantageous. For example, William Hogan proposes LMP, with FTRs to hedge congestion,[6] but provides no explanation of how the market would be administered in the absence of RTOs. The Commission should retain network and point-to-point services, which enjoy widespread industry support.

The absence of support for radical changes does not, however, mean the Commission should accept EEI's "don't worry, be happy" approach. EEI's description of how well the OATT is working for transmission providers does not mean it's working well for customers. As demonstrated in the initial comments of TAPS and others,[7] the OATT does not provide customers the comparable service and access to the competitive market Order 888 intended.

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[6] *See* Hogan Comments at 15-19. Even assuming this regime could be put in place outside RTOs, this cure is likely worse than the disease, in terms of cost to consumers. *See* TAPS November 9, 2004 and August 26, 2005 Comments in *Accounting and Financial Reporting for Public Utilities,* Docket No. RM04-12. The suggestion (Hogan Comments at 18) that LMP is needed to induce transmission investment and create long-term rights through FTRs is contrary to reality in all existing RTOs: there are no long-term FTRs; LMPs and FTRs create strong constituents to maintain congestion; and no one invests in transmission for the FTR value—once the investment decongests the grid, the value of the FTR is diminished. *See* TAPS June 27, 2005 Comments in *Long Term Transmission Rights in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Docket No. AD05-7-000. *See also* TAPS January 11, 2006 Comments in *Promoting Transmission Investment through Pricing Reform*, Docket No. RM06-4-000, at 16-20, 42-43 ("TAPS Pricing NOPR Comments").

[7] *See, e.g.*, Comments of Calpine Corp. at 24, 26-27, 30, 36, 38-40 (describing abuses at the hands of Entergy, among others); Lafayette Utilities System, Mississippi Delta Energy Agency, the Clarksdale Public Utilities Commission and the Public Service Commission of Yazoo City (same); Fayetteville (detailing grid inadequacies, among other problems); EPSA Comments at 13-15, 53 (describing functional unbundling enforcement problems, inadequate OATT staffing, and lack of comparable service) and Comments of the American Wind Energy Association ("AWEA Comments") (attaching the Statement of William L. Massey).

The three minor tweaks EEI suggests, while baby steps in the right direction, will not "alleviate concerns about undue discrimination" as EEI claims (Comments at 6).

? Requiring "transmission providers [to] make their transmission base case studies available to customers subject to security and confidentiality protections" (*id.*)— is too limited to enable customers to assess whether their loads and resources are being planned for in a manner comparable to those of the transmission provider, as Order 888 requires and FPA Section 217(b)(4) mandates. *See* Part V below.

? "Work[ing] with NAESB to develop guidelines for providing information regarding denials of transmission requests" (EEI Comments at 6), even assuming NAESB could reach consensus,[8] would not assure the absence of discrimination. Denial of service due to lack of ATC, even if on its face non-discriminatory (given current grid conditions) may well result from discriminatory grid starvation. Without disclosure of the basis for granting other requests, as well as the transmission provider's uses for bundled retail load, whether a denial is discriminatory will remain a mystery. The Commission should insist on greater transparency with regard to the TO's own uses of the system, and the planning and expansion process.[9]

? A Commission "recommend[ation] that NERC clarify the information that should be posted regarding TLR measures" (EEI Comments at 6) will not ensure the transparent and consistent calculation of ATC essential for non-discriminatory open access.[10]

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[8] As discussed in Part II below, NAESB has shown itself not well-suited to addressing competitively-significant issues.

[9] *See* TAPS Initial Comments at 41-43, 53-55, 84, 111-12.

[10] *See* TAPS Initial Comments at 28-31.

EEI's focus on incentives and "and" pricing, while opposing joint ownership and joint planning,[11] will move us further from solving what EEI concedes (at 3) to be the fundamental problem of grid inadequacy.

Thus, the Commission should adopt the key changes requested in TAPS' Initial Comments:

? <u>Update the obligation to plan and construct to include joint, or better yet, inclusive regional, planning, with the objective of providing reasonable access to competitive markets and opportunities for customers to invest in the grid on a comparable basis.</u> The culture must be fundamentally changed: instead of making the minimum upgrades necessary for each transmission request, viewed in isolation, transmission providers must make cost-effective upgrades required to provide reasonable access to competitive markets and reduce costs to consumers.[12] The Commission should shift the risk of an inadequate system (now borne by customers in the form of denial of cost-effective service) to the transmission provider, who has the ability to address the problem. It should require acceptance, through redispatch (with costs shared on a load-ratio basis), of timely designated network resources; and clarify rollover rights to permit reasonable access to the market. A TO should not be permitted to deny a request for transmission to a network customer (or require upgrades or mitigation whose cost is not shared on a load ratio basis) if it would have been accepted with the TO's load designated as sink. Nor should it have an option to decline to jointly plan with network customers and thereby deny credits for customer-owned transmission facilities.[13] Joint planning[14] and opportunities for joint ownership should be required.

? <u>Eliminate pancaked rates between transmission providers.</u> The Commission should order joint, non-pancaked rates where transmission systems are integrated, or strongly

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[11] EEI Comments at 7, 10, 21-31, 69-71, 78-79, 82-83.

[12] *See* Comments of the AEP Operating Companies ("AEP Comments") at 9-10 ("The Commission must encourage planning to achieve market efficiencies that benefit consumers with generators competing head-to-head. RTOs and other Planning Authorities should not institutionalize the status quo congestion that benefits one market participant over another while the consumer suffers.").

[13] *See* Part V below and Appendix A.

[14] *See* Comments of Xcel Energy Services Inc. at 10-11 ("where a request for service requires significant expansion of the grid, particularly jointly owned interfaces, it would be logical to utilize joint planning and open season processes to coordinate planning and to invite additional participation in a project. In that manner, grid expansion projects will more likely be right-sized to meet regional needs. … XES believes that the *pro forma* tariff could be modified to provide explicitly for joint transmission planning processes, including open seasons, both in connection with the provision of network and point-to-point transmission services under the *pro forma* tariff").

encourage such rates. Regional rates can equitably spread the cost of regionally beneficial upgrades and are better tailored to getting transmission built.[15]

? <u>Eliminate discriminatory pancaked rates for TDUs within a single transmission provider's system.</u> The Commission should eliminate OATT § 30.9's requirement that network-customer-owned transmission facilities provide specific benefits to the TO and its other customers, and require credits so long as the customer-owned facilities meet the standards applied to determine whether facilities may be included in the transmission provider's rolled-in rates.[16] By expanding credit eligibility, the Commission not only will ensure comparability, but will encourage investment in transmission expansion "regardless of the ownership of the facilities," as required under Section 1241 of EPAct 2005, and take an important step towards the joint system model that has been successful in promoting joint planning and getting transmission built.[17]

? <u>Treat retail and wholesale load served from behind-the-meter generation comparably and in a manner consistent with the obligation to plan.</u> Network customers should not be charged for transmission service to load that cannot physically be served from the grid.[18]

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[15] *See, e.g.*, AEP Comments at 4, 8 ("Regional markets demand a regional rate design"; "urg[ing] the Commission to adopt regionalization of 'highway' facilities as a national policy that can aid in the development of a more extensive network of critical interstate facilities that can unlock major efficiencies for the benefit of consumers"); AWEA Comments, Massey Statement at 13 (utility-by-utility pancaked rates create "barriers to trade [that] limit the geographical scope of markets, discourage entry, and reduce options for customers"); EPSA Comments at 31-32.

[16] The Commission's recent decision in *Southwest Power Pool, Inc.*, 114 F.E.R.C. ¶ 61,028 (2006), underscores the need to revise Section 30.9 to require crediting for comparable customer-owned facilities. The same transmission facilities that were determined under OATT § 30.9 *not* to qualify for credits (*id.* at P 11), apparently *would* be eligible for transmission owner compensation payments under SPP's proposals as an RTO (*id.* at P 22). There is no legitimate justification for this difference in treatment.

[17] *See* Part V below and Appendix A.

[18] *Florida Power & Light Co.,* 113 F.E.R.C. ¶ 61,290 (2005), extends load ratio pricing to terrain that the D.C. Circuit, in *Florida Municipal Power Agency v. FERC*, 411 F.3d 287 (D.C. Cir. 2005), found not controlled by Order 888—*i.e.*, where the network customer *cannot* take service for its full load due to physical limitations between the transmission provider's system and its own. Because these off-system physical limitations relieve the transmission provider of the obligation to plan to accommodate the customer's full load, the transmission provider's current ability to do so should be irrelevant given the planning justification for full load ratio pricing. Nor is this situation so common as to create administrative burden if the Commission were to revise the OATT to allow a narrow exception to load ratio pricing in the event of demonstrated physical impossibility that relieves the transmission provider of the obligation to plan. Particularly given the Commission's view that Order 888 affords only the transmission provider, rather than the customer, the opportunity to craft transmission services that meet customer needs, this issue should be addressed in the context of OATT reform.

? Make ATC, TRM, and CBM calculations transparent, consistent, auditable (and audited), and, better yet regional and independent, with CBM treated the same as other transmission reservations. TRM should be standardized in a manner that leaves no discretion as to whether, where, when, and how much capacity to set aside. CBM should be reserved and paid for like any other reservation or, at minimum, calculated, reserved, and paid for in a standardized, transparent, and comparable way.[19] A transmission provider should not be permitted to claim CBM while excluding TDUs from the reserve-sharing arrangements CBM is intended to facilitate.

? End non-comparable treatment of energy imbalances. The Commission should eliminate the $100/MWh penalty for under-deliveries outside the 1.5%/2 MW band and/or expand the return-in-kind bandwidth substantially, so that customers can have access to return-in-kind options comparable to what NERC and NAESB provide for control area inadvertent energy, or at least less punitive imbalance options.[20]

? Eliminate from Schedule 2 rates non-comparable compensation for the TO's reactive capability within the Order 2003 required range, and provide only for compensation, on a non-discriminatory basis, for reactive production outside that bandwidth. Treating fixed-cost recovery for a generator's reactive power capability within the Order 2003 deadband as a generation charge (not a transmission charge) achieves comparability and just and reasonable rates.[21] A less desirable means to achieve comparability would be to provide compensation for the full reactive capability of all generation on a non-discriminatory basis, but add a mechanism to restrict total reactive charges to just and reasonable levels. Current subsidies to the transmission provider's generation must end.

? Enforcement must be made meaningful, so that violating the tariff poses significant risk for the transmission provider rather than solely potential for competitive advantage.[22] The Commission's expanded penalty authority provides potent weapons against continued abuses, assuming the Commission wields them effectively. TOs must be held accountable for failing to fulfill their OATT planning and expansion obligations. Where lack of ATC forecloses access to alternatives, market-based rates should not be allowed and the transmission owner should be required to offer embedded cost-based sales.

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[19] *See, e.g.*, Comments of Ameren Services Co. ("Ameren Comments") at 9 ("Ameren Services submits that the standardization of procedures and transparency for determinations of TTC, ATC, Transmission Reliability Margin ("TRM"), and Capacity Benefit Margin ("CBM") can provide a framework for the Commission to determine whether discrimination has occurred…."); Comments of ELCON, AISI, and ACC at 5-6 ("ELCON Comments"); AWEA Comments, Massey Statement at 9-10.

[20] *See* Part II below.

[21] *See* AEP Comments at 10-12.

[22] *See, e.g.*, ELCON Comments at 9-10.

II. DISCRIMINATORY ENERGY IMBALANCE CHARGES MUST END[23]

EEI and some of its members[24] attempt to support imposition of $100/MWh penalties on transmission customer under-deliveries outside the narrow 1.5%/2 MW deviation band, while control area operators may return inadvertent energy in kind. Progress Energy (Comments at 26) argues "energy imbalances and inadvertent energy are not comparable," noting that inadvertent energy reflects the loads, generator outputs, and schedules of all entities within the control area. *Id.* at 25.[25] But that difference hardly justifies two vastly different regimens, as explained in TAPS' Initial Comments and its letters to NERC and NAESB.[26] In any case, that argument was rejected in Order 2000.[27]

Progress Energy's argument that, "If the transmission customer forms its own control area, its control area would have 'return in kind'/inadvertent energy, but they would have to incur the cost and responsibilities of maintaining a NERC certified control area"[28] demonstrates only that the Commission's current policy is heading in the wrong direction—promoting formation of new, small control areas to escape imbalance

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[23] This discussion relates to NOI questions PP 30 and 31 (Sections S.i and S.ii).

[24] Not all IOUs agree, as shown by the Nevada Companies' Comments at 60-63 and their imbalance provision, which does not have a $100 charge, and differentiates between helpful imbalances and harmful imbalances outside an expanded deadband. *See also* TAPS Initial Comments at 36-37 (describing BPA and Western Area Power Administration imbalance provisions).

[25] *See also* EEI Comments at 108.

[26] *See* TAPS Initial Comments at 31-37 and Attachment 2 thereto.

[27] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), *reprinted in* [1996-2000 Regs. Preambles] FERC Stat. & Regs. ¶ 31,089, *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), *reprinted in* [1996-2000 Regs. Preambles] FERC Stat. & Regs. ¶ 31,092, *petitions for review dismissed per curiam for want of standing sub nom. Public Utility District No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[28] Progress Energy Comments at 25. *See also* EEI Comments at 108-09.

penalties. As explained by former Commissioner Massey,[29] "Balkanized control area by control area markets cry out for greater consolidation of control functions."

This issue is firmly on the Commission's plate to solve, as demonstrated by the inability of NERC or NAESB to address the control area side of the equation. On November 29, 2005, NAESB's Wholesale Electric Quadrant modified the report by the Inadvertent Interchange Payback Task Force, which had been deliberating for more than two years, to make clear that it recommended retaining the return-in-kind regimen for control areas simply because of lack of consensus on this competitively charged issue.[30] The IIPTF Report's recommendation now reads:[31]

> The IIPTF reviewed numerous possible solutions to the settlement of Inadvertent Interchange and determined that, at this time, no consensus can be reached regarding alternatives to the NAESB Version 0 standard."

The Commission must promptly remedy this undue discrimination by eliminating imbalance penalties and/or significantly expanding the deviation band.

III. NATIVE LOAD — SECTION 217 DOES NOT SAY WHAT OTHERS CLAIM[32]

Comments filed in this proceeding suggest that Section 217, the Native Load Service Obligation provision of EPAct 2005,[33] does just about everything, including the windows. It does not. As described in TAPS' Initial Comments at 46-49,

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[29] AWEA Comments, Massey Statement at 14.

[30] *See* December 3, 2005 revised draft minutes of the November 29, 2005 WEQ meeting, along with the redlined IIPTF recommendation and attachment (the IIPTF Report), *available at* http://www.naesb.org/weq/weq_ec.asp (last viewed on Jan. 22, 2006).

[31] *Id.*

[32] This discussion relates to the NOI at P 9.

Section 217(b)(1)-(3) is narrowly drawn to preserve existing firm resource-to-load rights for transmission providers and load serving transmission customers on a comparable basis; Section 217(b)(4) directs the Commission to facilitate the planning and expansion of the grid to meet the reasonable needs of load-serving entities (*e.g.*, to access competitive generation) and to enable them to secure long-term rights for long-term power supply arrangements (*e.g.*, commitments to new generation resources or long-term power purchases). We quote below and respond to some of the overstatements.

> Section 217 provides that load serving entities … are entitled to use their *ownership rights* in transmission facilities, their firm transmission rights or equivalent tradable or financial transmission rights to meet those service obligations…. (EEI Comments at 19, emphasis added.)

Response: Section 217(b)(1)-(3) does not protect "ownership rights" separate and apart from existing firm resource-to-load transmission rights, as defined by the Commission. Rather, the scope of the protections offered by Section 217(b)(1)-(3) is limited to existing firm rights, encompassing both "implicit" firm rights of transmission owners (who are required to designate network resources to serve their Native Load in the same manner as Network Customers (*see* OATT § 28.2)),[34] and explicit firm rights set forth in transmission contracts and service agreements. Mere ownership of transmission facilities

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[33] EPAct 2005, § 1233.

[34] *See Wis. Pub. Power Inc. SYSTEM v. Wis. Pub. Serv. Corp.*, 83 F.E.R.C. ¶ 61,198, at 61,858, *order on reh'g*, 84 F.E.R.C. ¶ 61,120 (1998) (invalidating TO's improper network resource designations). *See also Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,451, P 118 (Aug. 29, 2002), reprinted in [1999-2003 Proposed Regs.] FERC Stat. & Regs. ¶ 32,563 ("SMD NOPR"). (Order 888 *pro forma* tariff requires vertically-integrated utilities to designate network resources in the same manner as network customers; these current network resource designations will be used for purposes of converting to network access service and assigning FTRs to preserve existing rights).

does not give the owner an existing firm right to the use of those facilities that is protected under Section 217(b).[35]

> Section 1233 permit[s] the transmission provider to reserve transmission rights for native load service, and therefore permit[s] the transmission provider to set aside transmission capacity for Capacity Benefit Margin and Transmission Reserve Margin. (EEI Comments at 13.)
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> In interpreting the native load protections provided by Section 1233 of the Energy Policy Act 2005, that provision should be read to codify all such protections provided by Order No. 888 (*e.g.*, transmission reservations for native load growth and for CBM). (Comments of Southern Co. Services, Inc. at 14 ("Southern Comments").)

Response: Neither CBM nor TRM are existing, firm, resource-to-load rights preserved under Section 217(b)(1)-(3). Nor are they long-term power supply arrangements for which the Commission should enable LSEs to obtain long-term rights under Section 217(b)(4).

Order 888's provision for load growth reservations[36] are consistent with Section 217(b)(4)'s mandate to facilitate the planning and expansion of the grid to meet the reasonable needs of LSEs to the extent the reservations are reasonable and applied on a consistent and comparable basis for both the transmission provider's native load and network customers (as well as any load serving point-to-point customer).

> Section 1233 should be construed to provide broader protections than those provided by Order No. 888 because the Act sets forth the general requirement that native load protections can never constitute discrimination in any

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[35] This is evident from the fact that Section 217 preserves the firm rights of customers to use of transmission facilities owed by TOs.

[36] Order 888-A at 30,220. *See also id*. at 30,220-21 (providing for TO reservations for native load and network customer load growth within the current planning horizon).

> aspect of Commission regulation…. (Southern Comments at 14.)
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> [L]oad-serving entities must not be deemed to have engaged in "undue discrimination or preference" under the Federal Power Act if their actions are directed to serving native load customers. (Southern Comments at 56.)

Response: Section 217 provides no generalized authorization to discriminate in favor of native load. Section 217(k) merely confirms the obvious—that mere use of the rights described in Section 217(b) (*i.e.*, the existing firm resource-to-load rights preserved under Section 217(b)(1)-(3)), to the extent required to meet a service obligation, would not constitute undue discrimination.

> By providing a native load preference, the Commission's pro forma OATT codifies how to deal with the "tension" described above. Whenever there is an issue about the right to use the system, the native load customer has a preference. Thus, there is no tension and no tension that needs to be addressed. (Ameren Comments at 10.)
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> [T]o the extent that there is any tension between the obligation to serve native load customers and to provide non-discriminatory access under the OATT and it is not possible to achieve both, then the priority must be given to the service of native load customers – a point that Congress has reinforced with its passage of the new FPA Section 217. (Nevada Companies Comments at 15.)

Response: Section 217 establishes no overarching preference for or priority to the TO's "native load" customers. Congress provided the identical treatment for all LSEs, whether they are TOs or TDUs. Existing firm resource-to-load rights are preserved, and the Commission is to facilitate the planning and expansion of the system to meet the reasonable needs of LSEs, and is to enable LSEs to secure long-term rights. Thus, Section 217 reinforces the need for comparability:

> In contrast [to native load and network customers], point-to-point customers who are not native load customers

> would not lose service completely in the event of a TLR because they typically use the system to obtain access to more economic sources of power and can obtain access to alternate sources of energy using the transmission systems where their loads are located. The Commission must reconsider its policy concerning curtailments of firm transmission service in light of the enactment of Section 217. (EEI Comments at 20.)

Response: Section 217 provides no basis for reconsideration of the OATT's requirement for non-discriminatory pro rata curtailments. Congress preserved existing rights of all LSEs, with no distinction between load serving entities that are point-to-point customers, and those that are network customers or transmission providers serving native load.[37] In any case, the OATT's non-discriminatory pro rata curtailment provision is an essential limitation on all existing firm rights.

> Clearly, it is Congress' direction that such capacity as is made available on an open access basis will be offered only once the service provider's service obligations have been met. …[T]his provision is critical in the evaluation of a utility's reservation of capacity in order to meet its service obligations and in connection with the evaluation of roll-over rights under contracts employing capacity needed to meet to its service obligations. (Comments of the Large Public Power Council at 6.)[38]

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[37] EEI's assumption that point-to-point customers have more flexibility to avoid curtailing load than transmission providers is inconsistent with reality for a small TDU that relies on point-to-point service for one leg of the contract path for its full requirements purchase or its major resource. There is no basis to assume the availability in a TLR situation of more economic sources or alternative sources from the TDU's competitor—the transmission provider on whose system the TDU's load is located. Rather, the TDU will likely have to face non-comparable $100/MWh imbalance charges as a result of the TLR.

[38] LPPC's further statement, "Congress determined that load serving entities (or 'LSEs') are entitled to use their *own* … capacity first, in order to meet their service obligations, without being subject to charges of unlawful discrimination" (Comments at 6, emphasis added), suffers from several of the errors discussed above. It erroneously extends Section 217(b)(1)-(3)'s protection to all transmission an LSE "owns," rather than just its firm resource-to-load rights at the time of enactment, and apparently grants TOs the rights to reclaim all such owned capacity for native load without charges of discrimination. As discussed above, Section 217 does no such thing.

> Section 2.2 erodes the native load protections established in Order No. 888 and expanded in Section 1233 of EPAct 2005. The Commission has held that a transmission provider cannot limit a transmission customer's rollover rights that conflict with native load growth unless the limitation was contained in the original service agreement. This requirement will deny native load priority to existing transmission capacity whenever native load grows in a manner that was not projected at the time a transmission customer's service agreement was executed. (Comments of Entergy Services, Inc. at 42-43, footnote omitted ("Entergy Comments").)

Response: Section 217 does not give transmission providers "first dibs" on their transmission capacity for use by native load, relegating open access (apparently including to other LSEs) to amounts left at any given time, as load grows. Rather, Section 217(b)(1)-(3) preserves firm resource-to-load rights existing as of the date of enactment of EPAct 2005; load growth not covered under those existing firm resource-to-load reservations is not protected. Section 217(b)(4)'s obligation to facilitate the planning and expansion of the grid to meet the needs of LSEs and to enable LSEs to secure long-term rights does not give any preference to TOs as compared with TDUs.

The argument that Section 217 provides TOs rights to recall capacity currently subject to rollover rights is particularly strained. If, as of the date of enactment, another LSE held a long-term firm right to certain capacity, then by definition the transmission provider was not holding firm rights to that capacity for native load and has no rights protected under Section 217(b)(1)-(3) with respect to that capacity now or in the future. The attributes of the firm rights preserved in Section 217 are defined (for transmission providers and OATT customers) by Order 888 and the OATT.[39] Thus, they are

[39] The implicit firm rights of transmission owners are subject to OATT § 28.2's requirement that a TO

consistent with the firm rights that should continue to be respected in the normal course of operation under the OATT, including applicable rollover rights.[40]

In short, Section 217(b)(1)-(3) requires no change to Order 888 or the OATT, and mandates comparable treatment of all load-serving entities.

IV. CALLS FOR "AND" PRICING SHOULD BE REJECTED[41]

Although we have not reviewed all of the initial comments submitted in this docket, the significant subset of comments we did review—including those of a geographically diverse sampling of transmission owners—reveals no groundswell of support for relaxing the "and" pricing prohibition to permit direct assignment of network upgrade costs to network customers (*i.e.*, participant funding). To the contrary, only a distinct minority advocates adoption of participant funding as part of the Commission's modification of the *pro forma* OATT.[42] Entergy presents the most vigorous and lengthy

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must designate its network resources for service to its native load in the same manner as network customers. *See* n.34 above.

[40] More generally, the Commission should reject the efforts of a number of TOs (claiming native load priority or otherwise) to completely gut rollover rights, and thereby deny customers continued rights to use the transmission system. *See, e.g.*, Entergy Comments at 41, 43-44 (proposing to deny use of rollover rights for changed resources); Southern Comments at 74-78 (providing for recapture opportunities). SPP's efforts (Comments at 7-9) to cut back on rollover rights because of constraints on its system highlights only its failure to fulfill its obligation to plan the grid. EEI's Comments (at 63, 67-68) highlight the lack of consensus among its members. As described in TAPS' Initial Comments at 75-80, 82-86, rollover rights are a TDU's lifeline. Until the grid is made consistently robust to assure TDUs reasonable access to competitive supplies without reliance on rollover rights, the Commission cannot restrict the availability and flexibility of rollover rights without assuring embedded TDUs rights to continue to rely on the transmission provider for the transmission required to deliver their power supply to their load on a cost-effective basis. Indeed, rollover rights should be clarified to encompass reasonable access to sources other than the incumbent. Only after the Commission provides TDUs real assurance of reasonable and cost effective access to the market, without necessarily relying on rollover rights, could it redesign rollover rights to be more closely tied to the planning process and better facilitate achievement of Section 217(b)(4)'s long-term rights directives.

[41] This discussion relates to NOI questions PP 12.1 and 12.6 (Sections B1 and B6).

[42] While the EEI expressed concerns about network customers ostensibly shifting upgrade costs to others in their selection of new network resources, it appears to propose to resolve this issue through means other than participant funding (at 76-77), and suggested that any departures from "higher of" pricing be

arguments for applying "and" pricing to network customers, in the form of participant funding for network upgrades,[43] and we therefore focus on its discussion of this issue.

Entergy notes that the Commission's "or" pricing policy results in rolling in, rather than directly assigning (through "participant funding"), the costs of network upgrades occasioned by network customers' selection of network resources.[44] Entergy argues that this policy

> does not result in efficient decisionmaking by transmission customers or generators. To the contrary, unless upgrade costs (other than facilities required to maintain reliability for existing services) are directly allocated to the network customer that causes those costs, inefficient decisionmaking is likely.

Entergy Comments at 11. Entergy asserts that "[e]nsuring that upgrade costs are assigned to those who cause them ensures that transmission customers will see the true societal costs of their various resource options." *Id.* at 16.

To illustrate its point, Entergy describes (*id.* at 12-14) a request by a group of Texas cooperatives[45] to designate as a network resource a new coal-fired generating station that is to be located in northeastern Arkansas (known as "Plum Point"):

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considered only on a case-by-case basis (at 29-30). At least one other very large IOU member of EEI—American Electric Power Company—submitted comments in this proceeding that are totally at odds with Entergy's participant-funding concept and the assumptions underlying it. *See* AEP Comments at 9-10.

[43] Entergy Comments at 9-19 and Attachment A to the comments.

[44] This is not the only option. Although the alternative of incremental pricing is somewhat more complex in the context of network service than it is in point-to-point service, "or" pricing can work in the context of network service. *See Midwest Indep. Transmission Syst. Operator, Inc.*, 109 F.E.R.C. ¶ 61,085, P 57 (2004) (applying Order 2003 crediting mechanism to network customers). While Entergy touts its participant funding alternative as being simple to administer (at 17), Entergy ignores the many issues that arise in attempting to assign costs under participant funding, including disputes as to whether a facility is an "economic upgrade" or a "reliability upgrade," and who has "caused" and/or who "benefits" from a needed upgrade. *See* n.60, *infra*.

[45] East Texas Electric Cooperative, Inc. ("ETEC"), Sam Rayburn G&T Electric Cooperative, Inc., and

> Plum Point is geographically and electrically remote from ETEC's load, which is located in East Texas. Plum Point is over 400 miles from the ETEC load, and the service ETEC is seeking will impact many highly loaded elements on the Entergy transmission system. ETEC chose Plum Point even though other generating resources are available in the proximate area ETEC serves.

Id. at 13. Entergy complains that rolling in the costs of network upgrades needed to accommodate ETEC's request would result in subsidization by Entergy's other customers of what Entergy characterizes as ETEC's selection of a poor power-supply option, and that assignment of the costs of the upgrades to ETEC is the way to avoid such supposedly economically inefficient results.

Entergy prominently featured the ETEC example in recent pleadings in its pending ICT application proceeding.[46] The Missouri Joint Municipal Electric Utility Commission ("MJMEUC"), a TAPS member and—like ETEC—a potential co-owner of the Plum Point station, submitted comments in the ICT proceeding that refute Entergy's claims.[47] MJMEUC showed that Entergy's Plum Point System Impact Study[48] would, if participant funding were allowed, assign significant upgrade costs to *all* of the would-be participants in the unit, with the sole exception of the town in which the unit is to be located. Other relatively nearby cities in Arkansas have already dropped out of the project in large part because of the threat of tens of millions of dollars in upgrade costs.

Tex-La Electric Cooperative of Texas.

[46] Answer of Energy Services, Inc., filed on November 21, 2005 in *Entergy Servs., Inc.*, Docket No. ER05-1065.

[47] Motion for Late Intervention, Protest, and Reply of Missouri Joint Municipal Electric Utility Commission, filed on December 7, 2005 in *Entergy Servs., Inc.*, Docket No. ER05-1065, *available at* eLibrary Accession No. 20051207-5042.

[48] The System Impact Study was for transmission service, *i.e.*, delivery of the output of the unit to the

MJMEUC also showed a service request for a combined 5 MW entitlement for two small Missouri towns that are located much closer to the unit than ETEC's loads are (*i.e.*, Thayer and Campbell, which are currently supplied by Entergy, but seek alternative supplies). The request was evaluated as requiring $14-28 million (and potentially more) in upgrades. The upgrades Entergy would assign to these small participants include work on 500 kV facilities that are located near Little Rock—*i.e.*, south and west of the unit, whereas these towns are northwest and north of Plum Point—and that are long-established constraints that perennially show up as requiring upgrades in order to accommodate virtually any variety of service request.[49] Since MJMEUC filed its comments on December 7, 2005, both Thayer and Campbell have decided not to participate in the Plum Point project. Both towns continue to be supplied by Entergy, although they have received notice that service will be terminated when their current contracts expire.

As MJMEUC's pleading demonstrates, Entergy's "cost causation" argument is deeply flawed. It rests on the convenient but artificial assumption that the need for transmission upgrades is caused entirely and exclusively by the last customer to request service, and that problems can be attributed to network customers who cavalierly designate network resources in far-flung parts of the transmission system. Contrary to Entergy's implication, transmission constraints affected the service request of nearly every potential Plum Point participant, regardless of its distance from the unit.[50] In the

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participants, not for interconnection of the plant.

[49] Entergy has made no response to MJMEUC's December 7 pleading in the ICT case.

[50] As MJMEUC pointed out (at 5-6), although Entergy had sought to blame this on a "poor siting" decision

case of Thayer and Campbell, it is difficult to conceive how the towns' tiny service request could be the sole reason for making upgrades to Entergy's 500 kV facilities, and in particular those that are remote from the towns and the unit and in the opposite direction from the contract path. A much more likely cause (or a much greater contributor to the cause, in any event) is the transmission owner's neglect of its transmission system and its refusal to expand the grid even when congestion is frequently and/or widely experienced.

It is not uncommon for TDUs' transmission service requests to be refused based on studies showing that affected flowgates (which would require upgrades to allow the reservation) are *already* significantly overloaded. MJMEUC has recently encountered this problem in connection with a request to the Midwest Independent Transmission System Operator ("MISO") for a 10 MW point-to-point reservation from the Ameren control area (in MISO) to Associated Electric Cooperative (outside of MISO). MISO's December 8, 2005 System Impact Study for this request[51] showed two heavily overloaded flowgate paths that would need to be upgraded, at an estimated cost of more than $6 million, in order for MJMEUC to have its 10 MW request granted.[52] The study shows flows of 314 MW on one such path with a TTC of only 191 MW; as to the other,

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by the plant's developer, the plant will be directly connected to a 500 kV line, which is itself part of a loop of 500 kV facilities that are in turn connected to other 500 kV lines that spread throughout the region.

[51] *Available at* http://oasis.midwestiso.org/documents/Miso/A269%20Final%20Report_rev4.pdf (last viewed Jan. 23, 2006).

[52] MISO's study initially identified (at 9) nine flowgate paths that would be adversely impacted by the request, and each one showed *negative* AFC (available flowgate capacity) well in excess of 10 MW, with the smallest being 22 MW and the largest overload in excess of 500 MW. MISO concluded (at 14) that three of these results were due to modeling error, three others would be relieved by other upgrades that were in the works, and one was resolved by a neighboring transmission provider "grant[ing] appropriate allocations," leaving the two flowgates with large negative AFCs discussed above.

the flows are identified as 1448 MW when TTC is only 1195 MW. Where, as here, there are identified overloads of 127 MW and 277 MW respectively, the conclusion is inescapable that MJMEUC's 10 MW request is not causing the need for upgrades. Nonetheless, under Entergy's reasoning, MJMEUC would be saddled with the entire cost of upgrades that would fix existing problems not of its creation.[53]

Particularly when a transmission system has been on a starvation diet for years, utilization of participant funding will have the predictable effect of maintaining the *status quo*—nothing will get built, while a game of "chicken" ensues. Faced with disproportionate upgrade costs, customers will forgo otherwise attractive transactions that would require expansion of the maxed-out transmission system, and congestion will only increase, causing economic harm to all users of the system.[54] As TAPS has recently recounted,[55] rating agency reports, testimony at Commission technical conferences, and experience all indicate that participant funding makes it less likely, rather than more likely, that needed expansion of the transmission system will occur as Congress clearly desires (*see* new FPA Sections 219, 217(b)(4) and 216).[56]

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[53] While the overloads identified by MISO likely have multiple causes, they may well have severely exacerbated by Ameren's recent addition of a large industrial load that is physically located outside of the MISO footprint—on the Associated Electric Cooperative transmission system—in southeastern Missouri. When Ameren proposed to pick up this load of nearly 500 MW, MISO concluded that it did not have to study the impact of this transaction on the transmission system because Ameren raised no concern. *See* Motion for Leave to Intervene Out-Of-Time and Answer of the Midwest Independent Transmission System Operator, Inc., filed March 2, 2005 in *Union Elec. Co.*, Docket No. ER05-485, at 3-5.

[54] These problems are by no means limited to the MISO and Entergy systems. *See, e.g.*, TAPS Initial Comments at 13-14, & n.24 (recounting similar issues in Southwest Power Pool).

[55] TAPS Pricing NOPR Comments at 17-20.

[56] Entergy claims (at 14) that "Section 1242 of the Energy Policy Act of 2005 ('EPAct 2005') encourages transmission pricing plans based on participant funding." This is simply incorrect. The referenced section permits the Commission to *reject* participant funding proposals *even if* they meet the requirements of Section 205 (just and reasonable and not unduly discriminatory). Contrary to Entergy's wishful suggestion,

Entergy's blame game—*e.g.*, fingering ETEC as shifting costs onto the other users of the transmission system—is also faulty in that it assumes that it is necessarily a TDU's "choice" to enter into arrangements that ostensibly cause the need for the upgrades (*see* Entergy Comments at 11-13). Contrary to Entergy's blithe assertions, TDU power supply alternatives are not like credit card offers with which consumers are constantly inundated and that are all more or less alike. TDUs usually have few if any alternatives from which they can acquire a long-term power supply with similar characteristics.[57] Participant funding would further circumscribe their options, to the point of leaving customers with no option but to purchase from the host transmission owner, who likely has market-based rates or, even if it does not, has no express obligation to continue to provide service.[58]

A rough (and admittedly parochial) analogy helps to illustrate the fallacy in Entergy's "cost causation" reasoning and the unfairness of its direct-assignment proposal. Suppose that a major employer—say a large federal agency—were to move from its current downtown DC location to Vienna, Virginia. Suppose further that WMATA concluded that its existing Metrorail operations could not accommodate the increase in

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this new section strongly signals Congress's skepticism about the value of participant funding as a transmission pricing mechanism, rather than endorsement or encouragement of the concept.

[57] Entergy's "economic" analysis (*id*. at 11-12) falsely assumes that all energy sources are fungible, and so the only thing that matters is price/cost. Many factors must be considered by a prudent load-serving entity in formulating a power-supply plan, such as the timing when a new resource will become available, the need to diversify fuel sources, and more generally spreading risk by having multiple suitably sized resources. Reasonably priced, long-term, stable power-supply opportunities are hard to find and not fungible.

[58] *See* Order 888 at 31,805-06. The Commission there stated "We … reaffirm our preliminary determination not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term," leaving the door open only a crack. *See* Order 888-A at 30,392-93 and Order 888-B at 62,110.

commuters to and from the Vienna Metro station resulting from the agency's move, and that it would need to acquire additional cars to handle any increase in ridership on the Orange Line during rush-hour periods. If Metro utilized the same sort of participant funding approach that Entergy advocates, under a best-case scenario it would charge each of the agency's employees who ride Metro—and no other users of the Metro system—for an allocated share of the costs of purchasing and maintaining the needed additional cars, and it would charge these costs on top of the employees' regular fare to or from Vienna.

If the agency employees complained about the unfairness of this cost burden, Metro would chastise them for "choosing" to work in a place where Metro does not currently have sufficient capacity to allow them to commute. Under the logic put forth by Entergy, Metro would advise them to instead seek employment near where the agency had been located, on the grounds that this is the more "economic" option. Of course, the employees would not likely consider such potential new jobs (if they exist) to be fungible with their existing jobs, any more than TDUs are likely to deem one power-supply option to be completely fungible with another.

Under a more extreme scenario, but one which more closely tracks Entergy's participant funding approach, each time an individual agency employee sought to obtain a Metro farecard, he or she would be informed that since Metro had no available capacity to allow the person to commute to and from work in Vienna, the employee would have to pay the entire cost of the purchase of the new Metrorail car that would be needed to accommodate this person (in addition to the cost of the farecard). One at a time, the agency's would-be Metro riders, even those that would come from stations relatively close to Vienna, would be faced with this proposal, and presumably would each in turn decline the opportunity to buy Metro a new railcar, choosing instead to drive, carpool, or take the bus, aggravating traffic congestion on the roads. It could be said that other Metro commuters will be held harmless, because Metro will avoid the need to invest in new railcars that would—eventually—give rise to a general fare increase. However, these commuters will still ride in packed Metro cars, and the Washington/Vienna region will experience other adverse economic consequences.

This more accurate version of the analogy points up another failing of Entergy's participant funding model. Transmission upgrades are inherently "lumpy," and seldom can (or should) be sized to exactly match the "incremental" customer's request, just as Metro cannot (and should not) buy one-seat railcars in response to increased ridership. Rolled-in pricing of transmission upgrades is fair because it recognizes that all users will benefit from the expanded capacity of the system (allowing native load, as well as other wholesale transmission customers, to access cheaper generation).[59] This, in fact, is how transmission owners, including Entergy, treat upgrades needed for their own purposes, including generation additions. When this occurs, TDUs on the system pay their share of those facilities. Conversely, where TDUs are burdened, in addition, with directly assigned costs of upgrades required for their network resource designations, Entergy and its other customers will have a free ride—they will get to use the increased capability of the system but will not pay any of the associated costs.

[59] It is for just this reason that the Commission has long held that rolled-in rate treatment of network facilities is appropriate even where facilities would not be needed "but for" a particular customer's request. *See, e.g., Northeast Tex. Elec. Coop., Inc.*, 108 F.E.R.C. ¶ 61,084 (2004); *Pub. Serv. Co. of Colo.*, 62 F.E.R.C. ¶ 61,013, at 61,061-62 (1993); *Midwest Indep. Transmission Sys. Operator, Inc.*, 98 F.E.R.C. ¶ 61,141, at 61,412 (2002); *Western Mass. Elec. Co. v F.E.R.C.*, 165 F.3d 922 (D.C. Cir. 1999).

Such asymmetry is antithetical to the notion of comparability that animates the OATT, and to which Entergy frequently refers with no apparent sense of irony:

> Network service provides a transmission customer with the same ability to use the entire transmission system to transmit power as the transmission owner. To provide this service the transmission provider is obligated to plan its transmission system in a manner that allows network customers to integrate their network resources and network loads on a basis that is comparable to the way the transmission provider integrates its own resources and loads. The transmission provider thus incorporates the network customer's identified network resources and network loads into its own long-term transmission planning. When (a) the customer has a right to use the grid in the same manner as the transmission provider and (b) the transmission provider is obligated to plan the grid in a manner that permits the customer to integrate its resources and loads in the same way the transmission provider integrates its resources and load, the costs of the transmission grid should be shared equally by the customers and the transmission provider (for purposes of serving the transmission provider's native load). That is, transmission costs should be allocated based on the ratio of the network customer's load to the transmission provider's load on the transmission system.

Entergy Comments at 23-24 (footnotes omitted). Entergy's discussion of network service pricing (with which we agree) flatly contradicts its arguments for participant funding for network customers.

It is telling that Entergy's arguments for participant funding repeatedly use the terminology of cost-causation, while avoiding expressions such as "those who benefit should pay." When looked at from a benefits standpoint, the case against participant funding is clear. Numerous commenters in this docket highlight the broader benefits to all users that will come from the investment needed to produce a robust transmission system. AEP states, at page 9 of its comments:

> [R]egional planning must be based on power flow models of the real world that avoid the temptation to pigeon hole projects by segregating them into "base" or "reliability" upgrades [the costs of which are rolled in] versus "economic" upgrades [which, under Entergy's approach, would be directly assigned]. The models for planning need to recognize transaction levels on the transmission grid that are realistic just as the models recognize peak load. The fact that longer-term firm transactions have not been finalized should not be used as an excuse to under-design the grid of the future. … In addition, AEP maintains that as load grows, the economic upgrade of today will be the reliability upgrade of tomorrow.

The comments of Xcel Energy Services (at 5) and the Nevada Companies (at 3) are to similar effect.

The Commission has correctly observed that participant funding in the hands of non-independent transmission owners is fraught with the potential for discriminatory application.[60] It can be used to squelch competition and enhance the competitive position of the transmission owner's generation, making embedded TDUs captive. Changing the OATT to allow participant funding would thus undermine the essential aim of Order 888, *i.e.*, the creation and fostering of a robust competitive marketplace on which the Commission can rely to ensure that rates and terms of wholesale electric service are just and reasonable. For this and all the other reasons discussed above, the Commission should reject Entergy's call to modify the OATT to permit participant funding.

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[60] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,846, P 696 (Aug. 19, 2003), III FERC Stat. & Regs. ¶ 31,146, at 30,523-24, *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), III FERC Stat. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (Jan. 4, 2005), III FERC Stat. & Regs. ¶ 31,171, *order on reh'g*, Order No. 2003-C, 70 Fed. Reg. 37,661 (June 30, 2005), III FERC Stat. & Regs. ¶ 31,190.

V. JOINT TRANSMISSION PLANNING CAN AND SHOULD BE REQUIRED[61]

Joint transmission planning is crucial to creation of the robust grid and competitive markets the Commission intends. In Appendix A, TAPS has attached proposed tariff language to address that need, and eliminate disincentives to joint planning contained in the current OATT.

Even though EEI admits that the grid is inadequate,[62] it asserts that there is no need for mandatory joint planning.[63] EEI's position should be rejected. As discussed in TAPS' Initial NOI Comments (at 11-18, 87-91), mandatory joint planning between a transmission provider and network customers is essential to assuring that all customers have meaningful access to competitive markets. We know of no transmission provider that has failed to plan for and roll-in transmission for its own loads and resources; joint planning is crucial to ensuring that network customers who are required to support a load ratio share of the costs of the grid will not be forced to subsidize the transmission provider, while their own needs are neglected. Although some regions of the country have voluntarily developed successful, inclusive joint planning processes (in connection with shared transmission systems,[64] inclusive standalone transmission companies, or inclusive regional transmission planning efforts), they are the exception, not the norm.

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[61] This discussion relates to NOI question P 20 (Section J).

[62] *See* EEI Comments at 21-23, 73-74. As demonstrated in TAPS' Initial Comments (at 11-18, *cf.* 75-81), the TOs' OATT obligation to plan for network customers is honored in the breach.

[63] EEI Comments at 69-70.

[64] Such models are described in the TAPS White Paper, *Effective Solutions for Getting Needed Transmission Built at Reasonable Cost* (June 2004), *available at* http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf (last viewed Jan. 22, 2006), and attached to TAPS' Pricing NOPR Comments.

Inclusion of network customer transmission needs in transmission owner planning on the same basis as the transmission owner's own needs is essential for long-term comparability of service and for system adequacy. Network customers must depend upon the TO's transmission system to provide reliable service to their customers. They cannot duplicate the system. For comparable service to be a reality, the system must be planned and built to meet their needs, just as it must be planned and built to meet the transmission owner's needs to provide service to its native load.

The proposed joint planning requirement should recognize the fact that planning processes will differ between utilities based on history, regional differences, size of system, degree of state regulation, nature of state regulatory requirements, the degree to which the system is intertwined with systems of its neighbors, the market design in the area, and any regional planning requirements or arrangements that exist (*e.g.*, in the Upper Midwest). In addition, network customer size and sophistication will vary. Therefore, the tariff should not impose a specific joint planning procedure. Instead, the tariff should require a joint planning process that meets the needs of network customers for continued reliable service to load, load growth, and new resources on the same basis that the similar needs of the transmission owner are met. The transmission owner should be permitted to file a detailed description of its joint planning process to obtain certainty that it is complying with the tariff, provided that it complies with the joint planning process filed with and reviewed by the Commission.

While some variation in process is to be expected, the joint planning process must provide full comparability. For example, although Order 888 requires the transmission provider to plan for the needs of network and native load customers on a comparable basis,[65] EEI requests that FERC make explicit that there is no obligation to plan for a network customer until it designates a network resource.[66] This is a step in the wrong direction. Because the lead time for constructing major transmission can be longer than for major baseload generation,[67] the basic highway facilities needed to create a robust grid and enable use of probable generation sites must be identified and constructed. IOUs do not wait to plan until after they have formally designated network resources for their own loads;[68] nor do successful joint planning processes that currently exist (*e.g.*, CAP-X 2020).

EEI's proposal would create a "chicken and egg" problem. Resources cannot be designated under OATT § 30.7 until the network customer can "demonstrate that it owns or has committed to purchase generation pursuant to an executed contract," or "establish

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[65] *See* Order 888-A at 30,220, 30,529-30 (*pro forma* Tariff at Preamble to Part III, §§ 28.1-28.3) (noting that Transmission Providers have an obligation to plan and expand the transmission system to accommodate Network Customers' planned resources and load growth). *See also Wis. Pub. Power Inc. SYSTEM v. Wis. Pub. Serv. Corp.*, 84 F.E.R.C. ¶ 61,120, at 61,659 (1998) (concluding that reservations for load growth must be supported by reasonable forecasts and "by a reasonable plan for network resources to meet that native load growth" *before* formal network resource designation).

[66] EEI Comments at 96-97.

[67] *See* comment of Jeff Wright, Director of the Infrastructure Division of the Office of Economic Projects Infrastructure Division, at the May 13, 2005 technical conference, *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources*, Docket No. AD05-3-000, Tr. 52 ("[I]t can take almost three times as long to construct a bulk transmission line, than it is to build a new coal-fired generation plant"). At least one RTO has announced plans to develop a ten-year planning process to replace its existing five-year system. Letter from Philip G. Harris to PJM Members and Interested Stakeholders at 1 (May 31, 2005) (Attachment A to TAPS June 27, 2005 Comments in *Long Term Transmission Rights in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD05-7).

[68] While Orders 889 and 2004 should impose some limits on communications between the transmission owner's transmission function and its marketing, sales and brokering function, a wide loophole was created by Order 2004's retention of the bundled retail load exception, over TAPS objection (and in response to comments, among others, that the NOPR's proposed elimination of that exception would prevent integrated resource planning). *See* Order 2004, 105 F.E.R.C. ¶ 61,248, PP 76, 78 (2003). If, as TAPS strongly suspects, the transmission provider is planning for the generation needs of its bundled retail load (at least on a general level) before a resource is formally designated, it plainly must do the same for network customers.

that execution of a contract is contingent upon the availability of transmission service under … the Tariff." However, for planning purposes and to determine whether they should commit the investment necessary to develop a new resource or to negotiate a detailed transaction that is contingent on transmission service, network customers need early information with respect to the likelihood of availability of transmission and the transmission construction requirements that may be needed to integrate a new resource into the system and deliver it to their loads.[69]

Joint plans must also be dynamic, living documents that do not simply gather dust on the shelf after they are completed. Transmission planning for a vertically-integrated transmission owner is not a static process or single event. It is multi-faceted and continuous, focusing on projected load growth in various areas of the system, flows on the transmission owner's system as influenced by changes in load and generation on adjacent systems, and projections related to the likelihood of generation additions in the region, in order to maintain an adequate and reliable system over the long term. These sorts of ongoing, flexible analyses should result in a long-term joint transmission plan that identifies, for all LSEs, likely additions to the system and alternatives.

Joint transmission planning also should involve efforts to eliminate or mitigate constraints that are causing TLR problems or, within organized markets, significant congestion costs. Such planning should focus on a determination of what is a reasonable level of import capability to target for a particular area in order to have reasonable access

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[69] As discussed in Order 2003-A, the transmission construction requirements needed to provide network transmission service are distinct from those required to provide interconnection service. Order 2003-A at P 545. Meaningful and inclusive joint planning would complement the interconnection process and should reduce interconnection queues by providing better and more useful early information to potential interconnection and transmission customers.

to the regional market and to significantly lessen congestion, and alternatives to achieve and maintain that import capability.

Finally, transmission planning needs to focus on the integration of specified new generating plants and long-term purchase contracts into the system for delivery to load. Planning for new resources is likely to proceed in stages. When a transmission owner reviews the possible sites for a large, new generating plant, for each site it will analyze the potential impact of the plant on flows on the transmission system and the magnitude of transmission improvements to the network that will be required above interconnection facilities, so that the power from the unit can be delivered reliably to the TO's load. Such analysis, conducted as part of the general planning process, will help the TOs to select an appropriate generation site, balanced by other factors.

A more detailed planning phase, aimed at producing a specific plan and design, will occur as the transmission owner selects a resource and site and moves forward to obtain required state siting approval and permits. At that point, transmission planning becomes a facility planning exercise, focusing on the particular new facilities to be built, alternative voltage levels, and routes, with a much higher degree of specificity. Finally, when a plant is approved to be built, the specific additions themselves must be designed for construction.

Thus, a transmission owner's transmission plans will change as changes occur in its system and surrounding systems, and as new resources are identified and move toward greater certainty. Section 217(b)(4) requires that network customer load growth needs and new resource opportunities and options be accorded the same treatment and benefits of the transmission planning process as the TO's loads and resources. Planning is an iterative process, and the TO will learn from the process as it develops. Its network customers need to be privy to the same information, knowledge, and opportunities to benefit from the planning process.

The only way to accomplish these goals and achieve comparability is to mandate a joint planning process with TDUs at the table at every stage. The joint planning process must include the following essential elements:

1. *Needs defined on a comparable basis, based on an analysis of all projected LSE loads and resources, and published, consistently-applied standards*

   a. All LSEs in the footprint should be required to submit 10-year projections of their loads and resources to the Transmission Provider to be used in the joint planning process. The projected loads and resources of all LSEs must be planned for on the same basis as the Transmission Provider plans for its own projected loads and resources.

   b. The objectives of the joint planning process must include[70]

      i. Maintaining fully reliable service to all loads dependent on the transmission system from designated network resources of each supplier over the long term, enabling network customers to secure long-term rights, consistent with Section 217(b)(4). In an organized market, this would include maintenance of sufficient simultaneous transfer capacity to support needed FTRs for all existing and new network resources.

      ii. Creating a robust transmission system that facilitates an open and robust wholesale market, and reduces congestion, so that delivered costs are reduced as mandated by FPA Section 219(a).

      iii. Honoring existing point-to-point commitments and new long-term requests pursuant to the tariff.

   c. In developing the standards to apply to all LSEs, it may be appropriate to look to the existing transmission planning standards that the TO applies to its own retail loads. Planning standards developed by regional reliability

[70] *See also* TAPS Balanced Principles, attached to TAPS Initial Comments as Attachment 3, which recommends that planning meet deliverability, delivery, and simultaneous feasibility needs (whether "reliability" or "economic"), such that facilities needed to connect load to its resources and to create a robust grid are built.

councils also could be adopted, so long as they are designed to address adequacy, as well as reliability issues.

2. *Opportunities for network customers to participate in the joint planning process, and to validate and gain confidence in transmission planning models*

a. The process must be fully open to participation by the network customers and existing and prospective long-term firm point-to-point customers, with all data disclosed and transparent, subject to appropriate confidentiality restrictions on use by market participants. All proposed base and changed cases, assumptions, and criteria must be made available, not simply the base case as proposed by EEI,[71] with adequate time for review and comment.

b. A joint planning committee, not dominated by the TO,[72] should be established that is responsible for the development of the system's short-term, mid-term, and long-term transmission plans, including establishing uniform planning criteria and assumptions for base and changed cases, and reviewing the results of such cases and agreeing upon final plans and sensitivity analyses.

i. A network customer should be permitted to be represented directly or by a consultant with expertise.

ii. By working closely with technical staff, the joint planning committee will develop a general familiarity with the modeling process and local conditions, building expertise that should facilitate and expedite subsequent transmission planning cycles and allow the Transmission Provider to share some of the modeling work. Although use of a joint planning committee will not eliminate the need for broader customer participation in the process (*e.g.*, opportunities to review and comment on data and models, publication of draft plans with opportunities for comment, etc.), it should increase customer confidence in the transmission

[71] EEI Comments. at 6.

[72] For example, the North Carolina Transmission Planning Collaborative's ("NCTPC") Oversight Steering Committee ("OSC") has eight voting members, equally divided between Duke Power, Progress Energy Carolinas, ElectriCities of North Carolina, and the electric cooperatives. The OSC seeks to reach decisions on reliability and enhanced transmission access planning by consensus. If it is unable to reach a decision by consensus, decisions are reached by majority vote; and in the event of a tied vote, an independent third party consultant is entitled to cast the tie-breaking vote. With respect to reliability planning, the decisions of the OSC are not binding on the transmission owners; but dispute resolution procedures are available to challenge a decision by the investor-owned utility not to abide by a decision of the OSC. *See* http://www.nctpc.org/nctpc/document/REF/2005-05-20/pagreement.pdf (last viewed Jan. 23, 2006).

planning process, facilitate review of transmission plans, and reduce the time needed for comment periods.

3. *Colorblind Selection of the Plan to be Implemented*

a. The same criteria, data, and timing requirements must be applied to the loads of the TO and its network customers and to the examination of potential new resources and supply contracts. Integrating new generation and purchased power contract resources of the transmission owner and its Network Customers must occur on the same basis and subject to the same nondiscriminatory and cost allocation criteria for determining feasibility of the construction of new transmission.[73]

b. Transmission Providers must move from general plans to detailed, specific facility planning for other LSEs at the same stage in generation or power contract development as they do for themselves. Transmission Providers must publish clear, consistently-applied criteria for when that shift will occur.[74]

4. *Dispute Resolution Must be Available*

a. The process must include an efficient dispute resolution process that provides independent expert oversight where a dispute arises with respect to data, assumptions, base or changed cases, and resulting plans to ensure that the process is implemented in a manner that complies with the intent of the joint planning requirement in the tariff.[75]

Development of a comparable, balanced Transmission Plan is crucial, but only one step in a larger process. Once a final Transmission Plan has been adopted, TOs

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[73] The strong presumption, however, should be in favor of roll-in for reasons discussed in Part IV, above.

[74] These shifts may be coordinated with processes available under the OATT and Order 2003.

[75] Alternative dispute resolution procedures may be appropriate, since many power projects will simply be abandoned if disagreements over transmission are not swiftly resolved. The voluntary North Carolina Transmission Planning Collaborative ("NCTPC"), for example, provides that Participants will abide by the decisions of the NCTPC Oversight Steering Committee ("OSC") (a group consisting of representatives of Duke Power, Progress Energy Carolinas, ElectriCities of North Carolina, and North Carolina Electric Membership Corporation), and it allows IOU Participants to supersede decisions concerning reliability planning that are inconsistent with good utility practice. SERC and NERC established criteria, or least-cost integrated resource planning principles. However, any Participant may request that the North Carolina Utilities Commission Public Staff render a non-binding opinion regarding: (a) any disputed decision of the OSC; or (b) any decision of an IOU superseding a decision by the OSC. If the parties cannot resolve their dispute with the help of NCUC Public Staff, any Participant may seek review by any regulatory or judicial body with jurisdiction. *See also* http://www.nctpc.org/nctpc/document/REF/2005-05-20/pagreement.pdf.

should be required to use best efforts to implement the Plan and update it regularly.[76] TAPS would like to see opportunities for joint ownership or other inclusive transmission investment models (*e.g.*, the "consortium approach" being explored by PJM, which would allow public power entities to share in the ownership of certain transmission projects),[77] or at least credits should be available through a revised Section 30.9 for transmission facilities constructed pursuant to the joint plan.

By imposing a joint planning requirement and requiring the process to be filed and reviewed by the Commission, as well as by adjudicating any disputes that may arise, the Commission over time will be able to establish best practices for joint planning and thereby advance the objective of achieving a reliable and adequate grid, consistent with FPA Sections 217(b)(4) and 219.

Appendix A contains suggested revised tariff language for Section 28.2 (Transmission Provider Responsibilities) and a new Section 36 (Joint Planning) that would require all transmission providers to establish joint planning processes. As explained in TAPS' Initial Comments at 11-18, 21-26, and 87-91, in conjunction with requiring joint planning, the Commission must also revise Section 30.9 to eliminate the disincentives to joint planning (*i.e.*, by eliminating language that allows the TO to effectively veto credits by simply refusing to jointly plan) and to provide for nondiscriminatory crediting for network customer facilities that are comparable to TO

[76] Based on the experience of TAPS members in joint planning processes, it is difficult to mandate a specific planning cycle for all TOs. ATCLLC produces a new transmission plan every other year, with updates in the intervening year. Some systems may require annual plans; and in areas with high rates of growth, new or amended plans may be required even more frequently. Planning cycles and updates should to be tailored to the particular circumstances that LSEs face.

[77] *See* TAPS Initial Comments at 51-52, 101-05. *See also* TAPS Pricing NOPR Comments at 9-15, 31-37.

facilities included in the TO's annual transmission costs. Suggested revisions to Section 30.9 also appear in Appendix A.[78] Adoption of TAPS' revised Section 30.9 would be a crucial step in moving the industry toward the joint system model that has been successful in getting transmission built.[79]

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[78] For simplicity, TAPS has eliminated the joint planning references from the credits section, imposing instead a comparability test. Assuming the transmission provider's joint planning process, as approved by the Commission, allows only transmission facilities developed through the joint planning process to be included in the transmission provider's revenue requirement (*i.e.*, its Annual Transmission Costs, as defined in the OATT), the same restriction would apply to limit new network customer facilities eligible for credits under Section 30.9 under the comparability standard.

TAPS stated in its Initial Comments (at 91) that the current Section 30.9's integration standard might be appropriately applied to determine credits for point-to-point customers. Although we have not submitted tariff language for point-to-point customer credits, we note that in adapting Section 30.9 for that purpose, the Commission should also eliminate the TO's veto where it fails to include the point-to-point customer in its joint planning.

[79] *See* TAPS White Paper.

CONCLUSION

The Commission should modify the Order 888 OATT as proposed above and in TAPS Initial NOI Comments.

Respectfully submitted,

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APPENDIX A

TAPS' PROPOSED TARIFF MODIFICATIONS FOR JOINT PLANNING AND CREDITS

30.9 Network Customer Owned Transmission Facilities: The Network Customer that owns existing **or new** transmission facilities that are ~~integrated~~ **interconnected** 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~~**, if owned by** the Transmission Provider ~~to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider~~**, would be eligible for inclusion in the Transmission Provider's Annual Transmission Costs, and must allow access to its transmission facilities through the Transmission Provider's OATT**. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

New Section 36 Joint Planning

The Transmission Provider shall establish a joint planning process with its Network Customers to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network Customers on a comparable basis. The joint planning process must be transparent, fully open to participation and monitoring by the Network Customers, and must use the same planning criteria and

procedures for Network Customers' needs as are used for the Transmission Provider's needs. The joint planning process must also include meeting service obligations to long-term firm point-to-point customers, and plans shall be available for review and comment by existing and prospective long-term firm point-to-point customers.

Section 28.2 Transmission Provider Responsibilities: Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers. **To facilitate the Transmission Provider's satisfaction of its planning obligations hereunder, it shall establish a joint planning process pursuant to Section 36.**