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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Information Requirements for Available Transmission Capability	Docket No. RM05-17-000

COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

The Transmission Access Policy Study Group ("TAPS") welcomes the Commission's May 27, 2005 Notice of Inquiry. TAPS believes that the calculation of TTC, ATC, TRM and CBM must be made transparent and standardized if the Commission is to have any hope of ensuring non-discriminatory open access. Indeed, it is long past the time when this standardization should have been achieved. Simply asking the industry to do it, without providing specific guidance, is no more likely to work this time than in 1999 when the Commission ordered NERC to develop a standardized methodology for deriving CBM.[1]

TAPS suggests that this Commission move the ball forward by taking the following steps:

- ATC – the transmission capacity that must be made available for commercial use – is a tariff term. The Commission should distinguish between the portions of the ATC determination that are reliability-based (*i.e.*, TTC, TRM) and those that are not required "for the reliable operation of the bulk power system"[2] (*i.e.*, CBM).
- The Commission should promptly address the reservation of CBM, a competitively-significant tariff term. In particular, TAPS thinks the Commission was on the right track when it proposed in the SMD NOPR

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[1] *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 F.E.R.C. ¶ 61,099 (1999).

[2] *See* Section 215(a)(3) of the Federal Power Act as added by Section 1211 of the Energy Policy Act of 2005, H.R. 6, 109th Cong. (H. Rept. 109-190), which was signed into law on August 8, 2005.

that CBM be reserved and paid for like any other reservation.[3] At minimum, the Commission should require that CBM be reserved and paid for in a standardized, transparent, and comparable way, as an adjunct to inclusive and equitable reserve sharing arrangements.

- As to TRM, the Commission should require transmission owners, through NERC, to develop a standard that leaves no discretion to the individual TO as to whether, where and how much capacity to set aside for this reliability purpose. TTC must also be calculated using standardized, well-defined, and auditable (and audited) rules.
- RTO formation need not be a prerequisite for calculating TTC and ATC on an independent, regional basis. Rather, the Commission should require regional and independent calculation of TTC and ATC. At minimum, immediate steps must be taken to make the process standardized and transparent.

I. INTERESTS OF TAPS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[4] As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members have long recognized that determination of ATC and its components is critical to open access, and have urged more active FERC supervision of this function. TAPS testified at the May 20-21, 1999 technical conference on CBM,[5] and previously filed comments with the Commission on this subject.[6]

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[3] *See Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,451 (Aug. 29, 2002), [1999-2003 Proposed Regs.] FERC Stat. & Regs. ¶ 32,563, P 333 ("SMD NOPR").

[4] TAPS is chaired by Roy Thilly, CEO of Wisconsin Public Power, Inc. Current members of the TAPS Executive Committee include, in addition to WPPI, representatives of: American Municipal Power-Ohio; Blue Ridge Power Agency; Clarksdale, Mississippi; ElectriCities of North Carolina, Inc.; Florida Municipal Power Agency; Geneva, Illinois; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric Co.; Missouri River Energy Services; Municipal Energy Agency of Nebraska; Northern California Power Agency; Oklahoma Municipal Power Authority; Southern Minnesota Municipal Power Agency; and Vermont Public Power Supply Authority.

[5] *See* Statement of Gary Mathis, Madison Gas & Electric Company, for May 21, 1999 CBM technical conference, Docket No. EL99-46-000.

[6] *See* April 23, 1999 TAPS Comments, Docket No. EL99-46-000; November 15, 2002 TAPS Comments on Specific SMD Preamble and Tariff Issues at 35-37, Docket No. RM01-12.

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II. COMMENTS

A. It's Time to Recognize CBM as a Tariff Issue That the Commission Should Promptly Address

As explained in the NOI (at n.7), "ATC equals Total Transfer Capability (TTC) minus Existing Transmission Commitments (ETC) minus Transmission Reserve Margin (TRM) minus Capacity Benefit Margin (CBM)." Transparency is lacking, and opportunities for discrimination are abundant, at each step in this process, particularly with the calculation of CBM. This problem goes to the heart of open access and the competitive markets the Commission has sought to foster. Order 2000 specifically found that mistrust of ATC calculations will constrain the market area, reduce competition, and raise prices for consumers.[7]

CBM, in particular, cries out for prompt and direct Commission action. As described in the NOI (P 7), it is a reservation of firm transmission capacity to accommodate import of remote generation pursuant to reserve sharing arrangements.[8] A

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[7] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), *reprinted in* [1996-2000 Regs. Preambles] FERC Stat. & Regs. ¶ 31,089, at 31,017 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), [1996-2000 Regs. Preambles] FERC Stat. & Regs. ¶ 31,092 (2000), *appeal dismissed for want of standing sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[8] NERC's 2001 Planning Standards, as quoted at page 2 of the Appendix F to the April 14, 2005 NERC

transmission provider's decision to set aside transmission capacity for emergency imports pursuant to reserve sharing arrangements[9] reduces the firm import capacity available to its competitors. Whether to reduce ATC for a CBM reservation, at which interface and in what amount, is a competitively significant decision that is driven by commercial choices made by the transmission provider's generation function. It reflects tradeoffs made by the generation/merchant function as to reliance on internal vs. external generation for sources of energy and reserves. There is no effective regulation of these decisions, which can involve substantial discretion. The lack of transparency, standardization, and auditable definition, coupled with the absence of procedures for CBM to be reserved and paid for like other transmission reservations, invites abuse.

In 1998, after noting the disparate treatment of CBM among the utilities that shared the same interface and that reservation of CBM involved economic considerations (*e.g.*, the reduced amount of reserves for generation adequacy vs. the benefits of releasing transmission capacity for firm use) that differed among utilities,[10] the Commission

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Long-Term AFC/ATC Task Force Report, define CBM as "the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies." The "reliability requirements" referred to are generation adequacy or reserve requirements that may exist in the regional reliability councils, under state regulation or in internal utility planning protocols, but they are not NERC reliability requirements. These requirements can be met in two ways – acquiring generating resources or reserving transmission capacity to get back-up from neighbors.

[9] The reserve sharing arrangements do not necessarily permit participation of transmission dependent systems, who must share the cost of the reservation and may bear the brunt of the reservation's impact in terms of foreclosing access to transmission capacity that could otherwise be used for firm imports.

[10] One utility had reserved substantial CBM, foreclosing competitors from firm use of a constrained interface while allowing it to import non-firm economy energy; another utility that was short on capacity claimed no CBM on the same interface, thereby maximizing firm imports. *Wisconsin Public Power Inc. SYSTEM v. Wisconsin Public Service Corporation*, 83 F.E.R.C. ¶ 61,198, at 61,857-58 (1998). CBM

recognized that "the exercise of this discretionary adjustment can turn on considerations (such as reduction of power supply costs and limiting the generation supply options of competitors) that involve the transmission provider's merchant arm rather than its transmission arm."[11] The Commission explained:

> [W]hile utilities make the CBM adjustment in their role of transmission provider, the decision as to how large an adjustment to make can be driven by the needs of their merchant arm. And, their merchant arms will, in turn, be motivated to consider not only direct supply costs, but the impact of the CBM decisions on competitiors.

We've been around this block several times before. In 1999, the Commission solicited comments and held a two-day technical conference, after which it issued an order "direct[ing] transmission providers to take several short-term measures to make their Capacity Benefit Margin (CBM) set-asides more transparent, more accurate and more widely available." July 28, 1999 Order in Docket No. EL99-46, 88 F.E.R.C. ¶ 61,099 at 61,236 (1999). Among other things, this Commission "recognized the need for a standardized methodology for deriving CBM" and, given the NERC process then underway for that purpose, set a December 1999 deadline for completion of this important, time-sensitive task.

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choices matched the utility's portfolio requirements.

[11] *Wisconsin Pub. Power Inc. SYSTEM v. Wisconsin Pub. Serv. Corp.*, 83 F.E.R.C. ¶ 61,198, at 61,858 (1998) (requiring compliance filing to explain computation of CBM, including comparison with practices of other utilities in the subregion, and to provide a forum for addressing the economic issues from the perspective of transmission customers). Protests were filed in 1998, but no action was taken until November 19, 2004, when the Commission by letter stated its belief that issues pertaining to the compliance filing had become moot because "[m]ore importantly, the CBM allocations at issue are now performed by the Midwest Independent Transmission System Operator, Inc. on an independent and regional basis," and noted that it would close the docket if no responses were received. After none were received, the Commission by letter order of December 15, 2004 accepted WPS' 1998 compliance filing.

A number of status reports (and years) later, NERC on May 17, 2002 filed a "Report on Actions of North American Electric Reliability Council Concerning Available Transmission Capacity" in Docket No. EL99-46. NERC's May 17, 2002 submission put the CBM issue squarely back in the Commission's court. Instead of developing "*a* standardized methodology for deriving CBM" as the Commission ordered in 1999, 88 F.E.R.C. at 61,238 (emphasis added), NERC left it to each region to develop its own methodology for calculating CBM pursuant to multiple choice guidelines, and left reservation of CBM to individual transmission provider prerogative.[12]

In the SMD NOPR, the Commission recognized that CBM is a commercial practice that permits transmission providers to withhold transfer capability to favor their own uses of the system, while making all transmission customers pay for it. The SMD NOPR described the abuse of CBM:

> During the Commission's outreach process, many commenters asserted that Capacity Benefit Margin ties up valuable transfer capability without a specific reservation and payment by the customers who receive the benefit of the set-aside. The subsidy occurs because, while part of the transfer capability is withheld from the market as Capacity

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[12] After much work, NERC developed what it terms a "standardized framework" (NERC's May 17, 2002 Pleading at 1) – a non-exclusive list of factors to be addressed in establishing CBM values –under which each of NERC's ten regions is to develop and document its own methodology for deriving CBM. *See* Attachment 2 to the May 17, 2002 NERC submission (Phase IIB—NERC Planning Standards, Measurements, and Compliance Templates on Transfer Capability Margins) at 2-3. Only two of ten items listed in NERC's "standard" are requirements – that CBM is an import quantity only and that the generation unit outages considered be restricted to those on the transmission provider's system. The remaining eight items merely require description or specification of the procedures used and elections made (*e.g.*, the allocation of CBM values among the transmission provider's interfaces). Four of the ten merely call for the rationale for inclusion or exclusion of certain factors (generation not connected to the transmission provider's system but serving load on the transmission provider's system; generation connected to the transmission provider's systems but without the obligation to serve; interruptible load; generation reserve sharing arrangements). NERC's "standard" not only accommodates as many as ten distinct regional methodologies (which may include "multiple choice" elements for the transmission providers that use CBM), but empowers each region to grant individual utility variances from its methodology.

> Benefit Margin, the wholesale transmission customers using the system pay the entire transmission cost (including that of the Capacity Benefit Margin) through their transmission charges, thus subsidizing the Capacity Benefit Margin beneficiaries. The use of a Capacity Benefit Margin has also been regularly challenged on the grounds that the host transmission provider is withholding transfer capability under the guise of Capacity Benefit Margin in order to thwart competition.

SMD NOPR, P 330. *See also* Appendix C to the SMD NOPR at 34,506-08 (2002), which describes abuses associated with transmission provider set asides for CBM and the absence of standardization. To address these abuses, the Commission proposed to "standardize the treatment of Capacity Benefit Margin to ensure that: (1) only customers benefiting from it pay for it; and (2) transfer capability needed to access resources on a neighboring system is treated consistent with all other portions of the transmission grid." SMD NOPR, P 331. In addition, to improve efficiency and remedy undue discrimination, the SMD NOPR proposed regional and independent calculation of ATC. SMD NOPR, P 333.

The April 14, 2005 NERC Long Term AFC/ATC Task Force Final Report documented the continued lack of standardization and lack of transparency of ATC calculations, and proposed initiation of NERC and NAESB standards development processes to achieve greater specificity and consistency, including with regard to CBM. Among other things, the Task Force Report found (at 3) that "[s]ome [transmission providers] use CBM and some don't use CBM" and that "[t]he scope of CBM varies by footprint." Thus, as shown by NERC's Task Force Report (and its 2002 submission), NERC does not require *any* transmission provider to calculate and reserve CBM. Even in those regions that use CBM, there is no regional methodology; it is entirely up to the individual, vertically-integrated transmission provider to determine if it wants to reserve CBM at all and at which interfaces, with no effective review of that determination.

So here we are, in mid-2005, with the SMD NOPR terminated,[13] but with much of the country not covered by RTOs and still subject to individual transmission provider ATC and CBM determinations, using methodologies that are not transparent and allow plenty of opportunity for favoring a vertically-integrated transmission provider's merchant function at the expense of competitors. Nor is there any requirement that CBM be reserved like other transmission reservations and paid for. Rather than repeat history and delay this process further, the Commission should segregate the competitively-charged tariff issues that will not likely be resolved by industry consensus and move forward to address those issues. Specifically, CBM should be resolved as a tariff issue, with associated business and reliability-related practices developed after the basic rules of the road are established by this Commission.

As noted above, the Commission has long recognized CBM as a source of abuse, allowing some competitors to withhold capacity from availability for firm service without a specific reservation; this withdrawn capacity is paid for by all transmission customers. It can have significant anticompetitive effects. The Commission has an obligation to remedy this long-standing source of undue discrimination.[14]

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[13] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Order Terminating Proceeding, 112 F.E.R.C. ¶ 61,073 (2005).

[14] *See New York v. FERC,* 535 U.S. 1, 27 (2002) ("Were FERC to investigate this alleged discrimination and make findings concerning undue discrimination in the retail electricity market, §206 of the FPA would require FERC to provide a remedy for that discrimination. *See also* 16 U. S. C. §824e(a) (upon a finding of undue discrimination, "the Commission shall determine the just and reasonable … regulation, practice, or contract … and shall fix the same by order.").

The Commission need not defer this issue to NERC. As described above, NERC's 2002 FERC submission and its 2005 Task Force Report, which document treatment of CBM that is literally all over the map, demonstrate that NERC does not mandate *any* reservation of CBM to ensure the "reliable operation of the bulk power system."[15] Nor is CBM a business practice capable of standardization by an industry-wide consensus-based organization tasked with developing uniform business practices and communications protocols. Rather, the appropriateness of calculating and reserving CBM and if so, how, by whom, under what conditions, and at what charge, is a competitively significant transmission policy and pricing issue that needs to be addressed squarely by the Commission.

TAPS therefore urges the Commission to directly and promptly identify CBM as a tariff issue and require that reservations be made transparent and paid for by those reserving it, with the conditions on and procedures for such reservations specified by tariff. At minimum, the Commission must require that CBM be reserved and paid for in a standardized, transparent, and comparable way, as an adjunct to inclusive and equitable reserve sharing arrangements (which TAPS believes are essential to ensuring that all load serving entities meet their obligations to supply of electricity while minimizing costs to consumers).[16]

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[15] *See* FPA § 215(a)(3) as added by §1211 of the Energy Policy Act of 2005. Section 215(a)(1) defines the "bulk power system" as "(A) facilities and control system necessary for operating an interconnected electric energy transmission network …; and (B) electric energy from generation facilities needed to maintain transmission system reliability." Compare the generation reliability requirements referenced in NERC's CBM definition, as quoted and described in n.8 above.

[16] This Commission and the courts have recognized that reserve-sharing services are important to small systems. *Mid-Continent Area Power Pool Agreement,* 58 F.P.C. 2622, 2635-36, *reh'g denied,* 59 F.P.C. 1651 (1977), *aff'd, Central Iowa Power Coop. v. FERC,* 606 F.2d 1156, 1172 (D.C. Cir. 1979). *See also Gainesville,* 402 U.S. 515 (1971). Reserve regimens that penalize small systems for their size have long

B. The Commission Should Require Transparent and Standardized Methodologies for TTC and TRM

TRM, as described in the NOI (P 7) is "the amount of transmission transfer capability necessary to ensure that the interconnected transmission network will be secure under a reasonable range of uncertainties in system conditions." No transmission provider should be permitted to reserve TRM except as required by clear NERC standards that leave no discretion to the utility.

TAPS believes that TRM reservations are abused today in some places to keep transmission capacity from competitors. Specifically, we believe some control areas are reserving transmission capacity for purposes defined as CBM – to accommodate generation reserve sharing arrangements – but calling it TRM. For example, we understand that the VACAR utilities reserve TRM for use in sharing operating reserves, but apply inconsistent practices as to whether TRM can be released for non-firm usage. TRM needs to be defined carefully to avoid such practices.

The NERC Task Force Report's finding (at 3) that "[n]early all [transmission providers] use TRM" demonstrates that something is fundamentally wrong with this

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been recognized as anticompetitive and unreasonable, while equalized percentage reserves appropriately recognizes the relative burdens and responsibilities for regional reliability. *See Gainesville Utils. Dep't, et al. v. Florida Power Corp.*, 402 U.S. 515 (1971) (affirming the Florida Power Corporation's rejection of a standby charges proposed on basis of largest unit); *In the Matter of Consumers Power Co.* (Midland Plant, Units 1 and 2), 6 N.R.C. 892, 1090 (ASLAB 1977) (finding failure to coordinate with small utilities on a terms which included sharing of reserves on an "equalized percentage basis" anticompetitive and unreasonable); *see also id.* at 1089 (reserves based on small utility's largest unit found unreasonable). To the extent recent orders (*e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,157, P 213 (2004), *order on rehearing*, 111 F.E.R.C. ¶ 61,043, P 46 (2005)), signal a departure from Commission recognition the need for not unduly discriminatory access to reserve sharing, the Commission should reverse course. Failure to adhere to these fundamental principles regarding reserve sharing will undermine Commission efforts to achieve robust markets in which large and small entities can compete, and will result in unjust, unreasonable and unduly discriminatory wholesale rates.

picture. If TRM is truly required for reliability, then *all* transmission providers should reserve it, not “nearly all.”

For these reasons, the Commission should require transmission providers, through NERC, to develop a consistent and transparent standard for calculating TRM that leaves no discretion to the individual transmission provider as to whether, where, and how much capacity to set aside for this reliability purpose. Indeed, if TRM is treated differently than CBM in terms of how it is reserved and paid for (as TAPS advocates above), it will be especially important to minimize gaming potential by clearly defining what can be reserved as TRM, so CBM is not permitted to masquerade as TRM.

Similarly, TTC determinations need greater standardization and transparency. The NERC Task Force Report (at 3) summarized the inconsistencies on TTC, with some transmission providers starting with TTC, others deriving it from ATC, and some not using it at all. The opportunity for gaming and abuse, to the detriment of the competitive market, is plain. For example, if TTC calculations already reflect reliability margins, a TRM reservation would double count that margin.

In sum, *all* of the factors used to calculate commercially available transmission capacity (including Available Flowgate Capacity or AFC) must be calculated using standardized and well-defined rules. If the rules are properly written, adequately-defined and auditable (and audited), the opportunity for doubling up on transmission reserves through the basic calculation of TTC and also through the calculation and reservation of TRM are minimized.

Thus, the Commission should call for NERC standards that provide for uniform determinations of TRM and TTC, subject to a demonstration by a region that engineering differences justify adjustments to the standard calculation methodology. The Commission should allow the NERC standards development process to move forward, but establish clear guidelines for both the timing and the substantive results to be accomplished by the process, so that the Commission can fulfill its obligation to ensure that ATC—a tariff term that defines the capacity that must be made available commercially—is determined in a just, reasonable and not unduly discriminatory or preferential manner.[17]

C. The Commission Should Require Transparent, Regional and Independent Calculation of ATC

ATC is an essential tariff term: the transmission capacity that must be offered for open access. The Commission has the obligation to ensure that the calculation is transparent and performed in a consistent, non-discriminatory manner.

The Commission has repeatedly recognized the importance of both independent and regional calculation of ATC. The opportunity for use of ATC determinations to foreclose competition is plain. In the NOPR leading up to Order 2000 [18], the Commission identified the difficulty of accurately computing TTC and ATC, and the inconsistency of methodologies among systems, as key economic and engineering inefficiencies that created barriers to competitive electricity markets, a conclusion affirmed in Order 2000 at 31,014. Order 2000 at 31,008-12, also recites numerous comments attesting to ATC posting and calculation problems (including examples of

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[17] The energy legislation just enacted by Congress expressly provides for this Commission "upon its own motion … [to] order the Electric Reliability Organization to submit to the Commission a proposed reliability standard … that addresses a specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section." Section 215(d)(5), as added to the Federal Power Act by § 1211 of the Energy Policy Act of 2005.

[18] *Regional Transmission Organizations*, Notice of Proposed Rulemaking, 64 Fed. Reg. 31,389 (June 10,

interfaces being reported as fully loaded in both directions), and at 31,017 identified more accurate estimates of ATC as an important benefit of RTOs. For these reasons, the Commission made independent calculation and posting of ATC a required function of Order 2000-compliant RTOs. 18 CFR § 35.34(k)(5).

While the recent order terminating SMD focused on the voluntary development of RTOs, that does not mean that ATC calculations must be left in the hand of individual transmission owners. Rather, structures can be developed to achieve independent and regional calculation of ATC without the formation of an RTO.

For example, in *American Electric Power Co. and Central and South West Corporation*, 90 F.E.R.C. ¶ 61,242, at 61,789, *order on rehearing*, 91 F.E.R.C. ¶ 61,129 (2000), the Commission conditioned approval of the proposed merger on independent calculation and posting of ATC, as interim mitigation that could be quickly implemented until AEP transferred control of its transmission system to an RTO. The Commission found that implementation of this interim mitigation measure, together with imposition of market monitoring:

> (1) will address several concerns raised by the Intervenors, such as manipulation of ATC and transmission service denials; (2) can be performed by independent third parties; and (3) can be implemented in a relatively short time frame.

Id. AEP contracted with SPP (before it was approved as an RTO) to perform that function.[19]

1999), [1999-2003 Proposed Regs.] FERC Stat. & Regs. ¶ 32,541, at 33,700.

[19] *American Elec. Power Co.*, 91 F.E.R.C. ¶ 61,208, at 61,747 (2000) (order on compliance filing).

MAPP calculates ATC on a regional basis for use in evaluating transmission requests under Schedule F of the MAPP regional tariff (*i.e.*, up to twelve months of monthly transmission service). However, MAPP's regional ATC calculation is not independent – significant elements of the calculation (*e.g.*, TRM; capacity used for native load and network customers) are provided by the TOs.

Thus, various avenues (short of full RTO participation)[20] can be used to get beyond individual transmission owner calculations of ATC. Given the Commission's findings that such calculations are a source of undue discrimination, it has an obligation to pursue such alternatives.[21] At minimum, immediate steps must be taken to make the process standardized and transparent.

Respectfully submitted,

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[20] The Commission has also recently recognized the ICT concept as potential avenue for independent calculation of ATC. *Entergy Services, Inc*, 110 F.E.R.C. ¶ 61,295 (March 22, 2005); *Order on Clarification*, 111 F.E.R.C. ¶ 61,222 (May 12, 2005); *reh'g for clarification granted*, May 23, 2005. However, serious questions remain as to whether the actual Entergy proposal would involve an ICT sufficiently independent as to be meaningful.

[21] *See* n.13 above.

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