

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Rules Concerning Certification of the
Electric Reliability Organization; and
Procedures for the Establishment,
Approval, and Enforcement of
Electric Reliability Standards

Docket No. RM05-30-000

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

On September 1, the Commission issued a Notice of Proposed Rulemaking¹ to amend its regulations to implement Subtitle A (Reliability Standards) of the Electricity Modernization Act of 2005,² which adds new Section 215 to the Federal Power Act. The Transmission Access Policy Study Group (“TAPS”), which has long participated in developing, and has actively supported, this reliability legislation, hereby comments on the proposed rule. The NOPR provides a strong foundation for establishment of a self-regulating reliability organization under Commission oversight, with authority to set and enforce mandatory reliability standards. In these comments, we highlight areas where the proposed regulation should be fine-tuned or bolstered to make reliability standards and enforcement more effective and fair, and then respond to many of the Commission’s questions. Our key points include the following:

- The final rule should distinguish among (a) an electric reliability organization (“ERO”) demand that an entity immediately comply with its standards; (b) public disclosure of confirmed violations; and (c) penalties, with only penalties subject to the 31-day waiting period pending FERC review.

¹ 70 Fed. Reg. 53,117 (Sept. 7, 2005).

² Title XII, Subtitle A, of the Energy Policy Act of 2005, Pub. L No. 109-58, 119 Stat. 594 (2005) (“EPAct 2005”).

We will have taken a giant step backwards if NERC's policy of disclosure of all confirmed violations is not reinforced by the final rule.

- All reliability standards under Section 215 of the Act should be ERO standards, incorporating only justified differences in application to the various regions (especially within the same interconnection). To facilitate consistency in interpretation and enforcement of standards, the ERO should review all enforcement actions before filing notices of penalties with this Commission. The ERO, and not the Regional Entity ("RE"), should interface with FERC on standards setting and enforcement.
- The Final Rule should provide guidance on what is required for balanced stakeholder decisionmaking. Specifically, the Final Rule should apply Order 2000's no single segment may veto, no two may control standard. Public meeting requirements should be specified.
- The Commission should broadly construe the directive that it not defer to the ERO on the effect of a standard on competition to make sure reliability standards accord with the Commission's pro-competitive policies. Congress recognized the inherent limits of a stakeholder-based organization to deal with the competitive impacts inextricably intertwined in many reliability standards and has directed the Commission to second guess the ERO on the fundamental question of whether viewed in its full context, including consideration of the Commission's tariffs (and policies and rules for jurisdictional transactions), a standard will have an adverse impact on competition. If another standard would achieve the reliability purposes without intruding as much on markets, or without advantaging one set of competitors at the expense of others, the Commission should remand to the ERO for consideration of the alternative approach.

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.³ TAPS members

³ 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

have long recognized the need for mandatory and enforceable reliability standards that ensure grid reliability. As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members are concerned that reliability standards not become a means to confer competitive advantages or disadvantages on particular types of market participants. For this reason, we view as crucial the oversight role to be performed by this Commission—the only entity in a position to assess reliability standards in the context of transmission tariffs, market rules, wholesale power rate schedules and associated rules, and related business practices.

TAPS actively participated in the development of the NERC consensus reliability legislation in 1998 and as it was modified over time, and has long supported its enactment.

Communications regarding these proceedings should be directed to:

Roy Thilly, CEO
WISCONSIN PUBLIC POWER INC.
1425 Corporate Center Drive
Sun Prairie, Wisconsin 53590
Tel: (608) 837-2653
Fax: (608) 837-0274
E-mail: rthilly@wppisys.org

Robert C. McDiarmid
Cynthia S. Bogorad
SPIEGEL & MCDIARMID
1333 New Hampshire Ave, NW
Washington, DC 20036
Tel: (202) 879-4000
Fax: (202) 393-2866
E-mail: robert.mcdiarmid@spiegelmc.com
cynthia.bogorad@spiegelmc.com

II. COMMENTS

A. *The Proposed Regulations Should be Modified to Enhance their Effectiveness*

The Commission's proposed regulations go a long way toward providing the framework for an effective self-regulating reliability organization and for the

development and enforcement of robust and effective reliability standards. The proposed rules generally adhere to the reliability legislation, strike a good balance between what needs to be spelled out in the regulations and what can be handled in the ERO's application or the delegation agreements, and provide a solid basis to guide implementation.

However, TAPS believes the language of the proposed regulations should be modified in certain respects either to bring them closer to the legislation or to better ensure the ability to the ERO and the Commission to fulfill their crucial reliability mandate. While our answers to the Commission's questions (in Part B below) suggest additional ways in which the final rule could be improved, this section proposes modifications and additions to the proposed regulations.

1. The Regulations Should Require Compliance and Registration to Help Achieve that End

As proposed by NERC in its comments filed this day in this proceeding, the Commission should require all users, operators and owners of the bulk-power system to comply with ERO standards and data requests, and to register as a mechanism to facilitate compliance and enforcement. A clear directive to comply will better connect reliability enforcement to the Commission's penalty authority. *See* FPA Section 316A, as amended by Section 1284(e) of EPAct 2005 ("It shall be unlawful for any person to violate any provision of part II or any rule or order issued under any such provision."). Registration of all users, owners and operators of the bulk-power system will facilitate enforcement and make sure that all such entities are on actual notice that they are subject to reliability standards. Effective implementation also would be aided by including

additional definitions, such as “user of the bulk power system” “and net energy for load,” as proposed in the NERC comments.

2. The Regulations Should Clearly Distinguish Among Demanding Compliance, Public Disclosure of Violations, and Penalties; Public Disclosure of Confirmed Violations Should be Required

Section 38.5 of the proposed regulations provides for an enforcement process in which after finding a violation, the ERO may impose penalties and must then file notice of such penalties and the record at FERC, with the penalties becoming effective no earlier than 31 days after such filing. *See* Section 215(e)(1) and (2). The proposed rule, however, does not clearly address steps short of a penalty that the ERO may take without waiting for FERC review. Although the proposed regulations provide for reporting to the Commission of all violations, they fail to expressly provide for public disclosure. This is a serious deficiency.

The final rule should distinguish among (a) an ERO demand that an entity immediately comply with its standards; (b) public disclosure of confirmed violations; and (c) penalties, with only penalties subject to FERC review and the associated the 31-day waiting period. We will have taken a giant step backwards if the ERO must stand idly by, watching its standards be violated during the 31 days minimum time a penalty awaits FERC approval, and if NERC’s recently adopted policy of disclosure of all confirmed violations is not reflected in and reinforced by the final rule.

Congress plainly contemplated that the ERO should be able to take steps short of a penalty without FERC approval. Section 215(e)(1) makes penalties discretionary on the ERO (“The ERO *may* impose ... a penalty on a user or owner or operator of the bulk-power system for a violation of a reliability standard... if the ERO ...[among other

things] files notice and the record of the proceeding with the Commission” (emphasis added)). This provision allows the ERO to refrain from pressing for penalties where mere disclosure of the violation is warranted given the nature of the violation and mitigation that has already been undertaken. Further, Section 215(e)(6) provides that “[a]ny penalty imposed under this section ... shall take into consideration the efforts of such user, owner or operator to remedy the violation in a timely manner.” This provision contemplates that the ERO may inform the user, owner, or operator of the need for compliance and/or the finding of violation prior to imposition of a penalty.

Disclosure of confirmed violations,⁴ pursuant to the Guidelines for Reporting and Disclosure adopted by the NERC Board of Trustees on June 15, 2004,⁵ is essential for reliability and a valuable part of the reliability enforcement regimen that should not be abandoned in the transition to an ERO. TAPS agrees with the Guidelines’ conclusion that “transparency is vital if stakeholders, regulators, and the public are to have confidence that the electricity industry is doing all that is necessary to ensure a reliable bulk electric system for North America.” *Id.* at 1. Openness and transparency regarding violations are not penalties, but rather are essential elements of a credible process. Otherwise no one will know about violations where no penalties are imposed and the ERO’s accountability for lax enforcement will be severely compromised. Nor should a letter informing the CEO of a company of its violation be deemed a penalty. Indeed,

⁴ Confirmed reliability violations are violations for which investigatory, decisional and appeal processes have been completed at the RE or ERO level. Thus, confirmed violations would include a violation found by an RE that is not contested; if the violation is contested, it would be confirmed by the ERO. ERO notices of penalty, whether or not contested, should be publicly filed with this Commission, as provided by the proposed rules (except, if necessary, in cases involving a Cybersecurity Incident).

⁵ Available at ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/DisclosureGuidelines-BOTApproved-6-15-04.pdf (last visited Oct. 7, 2005).

disclosure of violations is included among the Bilateral Principles. It should be included in the final rule.

The final rule should distinguish among ERO demands for compliance, disclosure of confirmed violations, and penalties, with only penalties subject to the FERC review and a 31-day delay. Further, the provision for reporting of violations should be revised to make clear that all violations are to be made public when confirmed.

3. The Commission Should Interface with the ERO, Not REs

Throughout the enforcement provisions, the proposed rule provides for the regional entity to interact directly with the Commission. For example, proposed § 38.5(a) provides: “The Electric Reliability Organization, or a Regional Entity, may impose... a penalty...”; § 38.5(a)(2) provides for service by the RE; § 38.5(d) also refers to the RE’s filing of the notice of penalty; § 38.5(d)(3) and § 38.5(d)(6)(i) provide for remand to the ERO *or* RE for further proceedings. These provisions should be revised to make clear that all penalties are imposed by the ERO, the ERO is the entity that files the notice of penalty and record with the Commission, and if a remand is required, the Commission remands the matter to the ERO, which may then remand to the RE. As explained in NERC’s comments, the ERO should be accountable to FERC and the regional entities should be accountable to the ERO.

Section 215(e)(1) and (2) authorizes the ERO to impose penalties and provides for Commission remand to the ERO for further proceedings, if necessary. While the ERO may delegate enforcement authority to an RE, it is critical to consistent interpretation and enforcement of reliability standards, a fundamental Bilateral Principle, that all enforcement actions go through the ERO; otherwise, the ERO will not be able to assure consistency and its authority will be undermined. Proposed § 38.5(b) seems to recognize

this need when it requires an RE to file with the ERO notice of any enforcement action it takes. Inconsistently, the proposed regulations allow the RE to file the notice of penalty with this Commission. *See* proposed § 38.5(c).

The final rule should clarify that it is the ERO that takes enforcement actions and interfaces with the Commission regarding such actions. This will afford the opportunity for ERO review of RE enforcement actions. If a remand is ordered, the ERO may further remand the proceeding to the RE, but the Commission should remand to the ERO, not an RE. In this way, accountability and consistency can be achieved.

4. The Final Rule Should Provide Guidance on Balanced Decisionmaking and Public Meetings

Proposed §§ 38.3(b) and 38.7(c) incorporate essentially verbatim the legislation's governance requirements for the ERO and REs. *Compare* Sections 215(c)(2) and (e)(4). The final rule should go a step further and provide additional guidance on key points: (a) the requirement for balanced decisionmaking in any ERO committee or subordinate organizational structure and the requirement for balanced stakeholder (or hybrid) boards at the RE level and (b) public meeting requirements. Commission guidance at this juncture will go a long way to ensuring the credibility of ERO and RE procedures and decisions.

The original NERC “consensus” legislation included a requirement that the governing structure of the ERO “ensure[] that no 2 industry sectors have the ability to control, and no 1 industry sector has the ability to veto, the [ERO]’s discharge of its responsibilities as the electric reliability organization....”⁶ Although in a later process of shortening the reliability legislation the concept of “balanced decisionmaking” was used

in lieu of this detail, the final rule should spell out the meaning of balanced decisionmaking and balanced stakeholder representation so the industry has clear guidance in development of the ERO's rules and delegation agreements.

Including this articulation of the balanced decisionmaking requirement in the final rule would be consistent with Order 2000's standard for RTOs with stakeholder boards: "Where there is a governing board with classes of market participants, we would expect that no one class would be allowed to veto a decision reached by the rest of the board and that no two classes could force through a decision that is opposed by the rest of the board."⁷ Indeed, this standard draws from Order 888's independence requirement:⁸

The ISO's governance should be structured in a fair and non-discriminatory manner. ... [A]n ISO should be independent of any individual market participant or any one class of participants (e.g., transmission owners or end-users). A governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner. The ISO's rules of governance, however, should prevent control, and appearance of control, of decisionmaking by any class of participants.

Spelling out the meaning of the "balance" requirement would not only be consistent with Orders 888 and 2000, but would also comport with the Bilateral Principles, which expressly adopt the "no single segment should be able to veto and no two sectors should be able to control" standard. If decisions by stakeholders on ERO

⁶ See, e.g., 146 Cong. Rec. S629 (daily ed. Feb. 10, 2000).

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 31,074 (1999) ("Order 2000"), *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 Order 888 at 31,730-31. See also *Pac. Gas and Elec. Co.*, 77 F.E.R.C. ¶ 61,204, at 61,817 (1996)

committees and RE boards are to command the respect of the governments and the public served by this international reliability organization, specification of how this bedrock balanced decisionmaking principle will be achieved must be included in the final rule.

The integrity of the ERO's processes would be further advanced by defining in the final rule the "subordinate organizational structures" to which the balance requirement applies. TAPS proposes incorporation of the following definition:

"Subordinate organizational structure" means, with respect to the electric reliability organization or a regional entity, its committees and any subcommittees, task forces or working groups within the electric reliability organization or regional entity that are subordinate to its committees.

Such definition is necessary to make sure the balance requirements are not circumvented.

In addition, the final rule should incorporate public meeting requirements, consistent with the original NERC "consensus" legislation. Proposed § 38.3(b)(2)(iv) adopts verbatim the legislation's requirement for "opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards, and otherwise exercising [the ERO's/RE's] duties." TAPS asks that this provision be supplemented by the following:

Such rules shall provide, among other things, for notice and opportunity for public observation of all meetings of the electric reliability organization, its committees and subordinate organizational structure, except that the rules may include alternative procedures for emergencies and for the discussion of matters that should appropriately take place in closed session, such as litigation, personnel actions, commercially sensitive or critical energy infrastructure information, or enforcement or investigative matters.

(applying the "no single sector may veto, no two may control" standard to the California ISO).

This language largely tracks the language from the original NERC “consensus” legislation that, on the assumption it was subsumed by the more general openness requirements, was cut in the process of shortening the legislative language. However, the language clearly belongs in the ERO regulation to guide the industry in developing rules for the ERO and RE. Sunshine is crucial to the ERO’s garnering and maintaining the confidence of the public, state regulators, and the industry. It is key to the openness and transparency of a quasi-public body with substantial responsibility to act in the public interest.

As discussed in Part B, Response to Question 8 (¶63) below, TAPS cautions against the Commission’s proposal to conduct enforcement actions regarding Cybersecurity Incidents completely in secret. While confidential treatment may be warranted at particular stages in the process, or with regard to particular information, the proposed complete cloak of secrecy and exclusion of the public threatens core principles underlying our nation’s administrative and judicial processes.

Finally, as discussed in Part B, Response to Question 13 (¶71)(5) below, TAPS strongly supports the proposed rule’s provision for public notice and participation in Commission enforcement review actions. The public, particularly those directly harmed by a violation, have a strong interest in participating in Commission proceedings to review ERO penalties.

5. Audits and Periodic Recertification, Rather than Penalties,
Are the Best Mechanism to Ensure ERO and RE
Compliance

Proposed § 38.6 would subject the ERO and RE to decertification and civil penalties if necessary and appropriate to achieve compliance. TAPS recommends deleting the reference to civil penalties, which seem counterproductive in the context of

non-profit entities. *See* Part B, Response to Question 18 (¶78), below. Rather, decertification (but leaving no gaps in coverage), along with audits and periodic recertification (*e.g.*, every six years, as proposed in the NERC Comments), seem better suited to achieving Congress's goals.

6. ERO Funding Requirements Should be Clarified

The final rule should define the scope of the ERO funding requirements to include not only the costs associated with all ERO activities to achieve the purposes of Section 215, but also RE costs for functions exercised in support of achieving the purposes of Section 215, as urged by NERC in its comments. In addition, TAPS supports NERC's proposal for addressing the budget in the event of extraordinary and unforeseen circumstances.

B. Responses to Selected NOPR Questions

1. (¶ 8) On August 9, 2005, the Federal-Provincial-Territorial (FPT) Working Group in Canada and DOE jointly submitted to the Commission "Principles for an Electric Reliability Organization that Can Function on an International Basis" (bilateral principles) based on these stakeholder dialogues....We invite comment on those principles.

TAPS strongly supports the Bilateral Principles, which provide for funding on a net energy for load basis, consistent interpretation and enforcement of standards, and implementation of the "no single sector may veto, no two may control" rule for stakeholder governance. Because of both the high quality of the principles and the international effort that created them, the principles should be incorporated in the final rule.

2. (¶ 42) [W]e seek comments on what would constitute a reasonable length of time for such periodic certification [of the ERO] to be effective. For example, is a five-year certification period appropriate? How far in advance should an ERO be required to submit its application for recertification before its current certification period expires?

TAPS supports recertification every six years, as proposed in NERC's Comments.

3. (¶ 43) We seek comments on whether the term "end users" should be defined for purposes of the ERO's equitable allocation of reasonable dues, fees and charges among end users? Should "end users" be defined as customers using net energy for load? Should the term "end users" be defined in terms of those who directly or indirectly use the transmission system since "Bulk-Power System" is defined to exclude facilities used in local distribution of electric energy? Should "end users" be limited to entities transmitting electricity through the transmission facilities of others? Or, might "end users" include the transmission facility owners and operators whose businesses depend on the reliable operations of the interconnected Bulk-Power System?

"End users" is a term used in the legislation only in the context of the statutory test for ERO funding: "allocate[s] equitably reasonable dues, fees, and other charges among end users for all activities under this section." Section 215(c)(2)(B). If a definition is required, the term should be defined as all load served at retail, using net energy for load.⁹ This is the way the term was understood in the Bilateral Principles, which specifically provide for funding based on net energy for load. It also makes sense. All load served directly or indirectly from (or backed up by) the bulk power system depends on bulk power system reliability. The suggestion that end users should be limited to third party wheelers is at odds with the plain meaning of the legislative language, makes no sense, and would result in discriminatory funding burdens.

4. (¶ 48) Proposed Section 38.4(b)(3) provides that the Commission will not defer to the ERO or a Regional Entity with respect to the effect of a Reliability Standard or modification to a Reliability Standard on competition. How should the Commission define "competition" in this context? Commenters are asked to provide examples regarding the effect of a Reliability Standard on competition.

⁹ As proposed in the NERC Comments, net energy for load should be defined as: "balancing authority area generation (less station use), plus energy received from other balancing authority areas, less energy delivered to balancing authority areas through interchange. It includes balancing authority area losses but excludes energy required for storage at energy storage facilities."

The statutory exclusion of the effect on competition from the matters on which this Commission may defer to the technical expertise of the ERO reflects Congressional recognition of the inherent limits of a stakeholder/volunteer-based organization to deal with the competitive impacts inextricably intertwined in many reliability standards. While the ERO process can be counted on to develop standards that from a technical viewpoint get the job done, they cannot be relied upon to develop standards that minimize the impacts on competitive markets and which do not confer significant competitive advantages on some market participants at the expense of others.¹⁰ Among other things, the ERO standard setting process will be based on weighted industry voting, which is not well-suited to neutrally assessing competitive impacts or protecting minority interests. Rather, the Commission, which alone is in a position to evaluate the effect of proposed standards in the full context of its tariffs, rules and policies for jurisdictional services, and associated NAESB business practices, is required by statute to make sure that the standards are consistent with its pro-competitive mission, as recently reaffirmed by Congress.

The Commission's obligation to assess the competitive impact of proposed reliability standards is inherent in the reliability provision's adoption of the "just, reasonable, not unduly discriminatory or preferential, and in the public interest" test. Section 215(d)(2). The courts and the Commission have long recognized that these standards require consideration of competitive impacts. In 1973, the Supreme Court said

¹⁰ Indeed, the potential for competitive effects from reliability standards is highlighted by NERC's market interface principles which, among other things, provide: "An Organization Standard shall not give any market participant an unfair competitive advantage." The principles are available at ftp://ftp.nerc.com/pub/sys/all_updl/tsc/stf/ReliabilityandMarketInterfacePrinciples.pdf (last visited Oct. 7, 2005).

that the Commission's "important and broad regulatory power... carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations..." *Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 758-59 (1973). The DC Circuit, citing *Gulf States*, wrote that the Commission's regulatory authority gives the Commission the duty to consider the anticompetitive effects "of any proposed action by a public utility."¹¹ The Commission, also citing *Gulf States*, required Florida Power and Light to show that the tariff limitation it selected was "the *least anticompetitive means* of solving any ... operational problem."¹² Thus, Congress's new requirement that the Commission assess without deference the effect of a proposed standard on competition grows out of and reinforces the Commission's long standing responsibilities.

In terms of how to define "competition," the Commission should do so broadly so as to encompass the full picture of the competitive advantages and disadvantages created by standards for those subject to the standard, including as compared to the rules applicable to those not subject to the standard. Competition takes place not only via prices, but also via quality of service,¹³ and proposed standards that would, for example, adversely affect service quality for some entities (*e.g.* non-control area utilities) and not others (*e.g.*, control area utilities) should be found infirm. In Order 888, the Commission broadly defined "competition," stating that its authority covers more than antitrust violations: "we disagree with the argument that we are limited to applying a traditional

¹¹ *City of Huntingburg v. Federal Power Commission*, 498 F.2d 778, 783 (D.C. Cir. 1974).

¹² *Florida Power & Light Co.*, 8 F.E.R.C. ¶ 61,121, at 61,468 (1979) (emphasis added).

¹³ See, *e.g.*, U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, Section 0.1, n.6 ("Sellers with market power also may lessen competition on dimensions other than price, such as product quality, service, or innovation").

antitrust analysis in determining whether market power exists in the transmission system.”¹⁴ It also observed that transmission is only one of many areas relevant to competition: “In undertaking these initiatives, however, we are mindful that they are part of a broader picture of evolving issues affecting the electric industry and that other Commission policies will play an important role in ensuring the full development of competitive markets.”¹⁵

As the Supreme Court made clear in *Federal Power Commission v. Conway Corp.*, 426 U.S. 271, 279-80 (1976), in determining whether a wholesale rate is just and reasonable, the Commission must examine the entire factual context, including the competitive implications of the relationship between wholesale and retail rates. So too must this Commission consider the competitive impact of a standard in the context of retail and wholesale markets, as well as in the context of other jurisdictional tariffs, rate schedules, rules and policies, and business practices.

In light of the Commission’s long standing and well recognized role in examining the competitive effects of its actions and those subject to its jurisdiction, the Commission should broadly construe the Congressional carve out as a direction to make sure reliability standards accord with the Commission’s pro-competitive policies.

Specifically, Congress has directed the Commission to second guess the ERO on the

¹⁴ *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. 21,540 (May 10, 1996), [1991-1996 Regs. Preambles] FERC Stat. & Regs. ¶ 31,036, at 31,683 *clarified*, 76 F.E.R.C. ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), [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).

¹⁵ Order 888 at 31,652.

fundamental question of whether the standard is the least anti-competitive means of achieving its reliability purpose. If another standard would achieve the same purposes without intruding on markets, or without advantaging one set of competitors at the expense of another, the Commission should remand to the ERO for consideration of the alternative approach.

Examples of reliability standards having an effect on competition that the Commission must address in the context of its tariff are not hard to find. They underscore the inappropriateness of deferring to the ERO on questions of competitive effects.

ATC/TTC/CBM/TRM: The opportunities for discrimination afforded by the calculation of ATC, TTC, CBM and TRM pursuant to reliability standards go 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.¹⁶

For example, CBM is a reservation of firm transmission capacity to accommodate import of remote generation pursuant to reserve sharing arrangements. As detailed in TAPS' August 15, 2005 Comments in *Information Requirements for Available Transmission Capability*, Docket No. RM05-17, the lack of transparency, standardization, and auditable definition, and the absence of procedures for CBM to be reserved and paid for like other transmission reservations, invites abuse. A transmission provider's decision to set aside transmission capacity for emergency imports pursuant to reserve sharing arrangements reduces the firm import capacity available to its

¹⁶ Order 2000 at 31,017.

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.

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,¹⁷ the Commission 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."¹⁸ The Commission explained:

[W]hile utilities make the CBM adjustment in their role of transmission provider, the decision as to whether to make such an adjustment and how large an adjustment to make can be driven by the needs of their merchant arms. And, their merchant arms will, in turn, be motivated to consider

¹⁷ 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 choices matched the utility's portfolio requirements.

¹⁸ *Id.* 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's 1998 compliance filing.

not only direct supply costs, but the impact of the CBM decision on competitors.

In 1999, the Commission “direct[ed] 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.” *Capacity Benefit Margin in Computing Available Transmission Capacity*, 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. *Id.* at 61,238.

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. 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.¹⁹

¹⁹ 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

Predictably, NERC's April 14, 2005 Term AFC/ATC Task Force Final Report documented continued lack of standardization and lack of transparency of ATC calculations.²⁰ 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." As shown by these findings, NERC does not require *any* transmission provider to reserve CBM. Even in those regions that use CBM, there is no regional methodology; it is entirely up to the vertically-integrated transmission provider to determine whether it wants to reserve CBM at all and at which interfaces, with no effective review of that determination. Yet, it remains a reliability standard. In the SMD NOPR, at P330,²¹ the Commission again recognized the anticompetitive impacts of the flexibility allowed to transmission owners with regard to CBM.²²

NERC's failure to effectively address CBM even in the face of the Commission's 1999 directive highlights how poorly suited a consensus-based process is to develop standards that would remove competitive advantages from well-funded players, who can afford to populate the task forces, working groups, etc. It also graphically demonstrates why it is critical for the Commission to squarely address, without deference, all issues pertaining to the effect on competition of CBM and the other components of the

providers that use CBM), but empowers each region to grant individual utility variances.

²⁰ Available at ftp://www.nerc.com/pub/sys/all_updl/mc/ltaf/LTATF_Final_Report_Revised.pdf (last visited Oct. 7, 2005).

²¹ *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 330.

²² See also Appendix C to the SMD NOPR at 34,506-08, which describes abuses associated with transmission provider set asides for CBM.

competitively crucial ATC determination²³—the determination that defines the grid available to the transmission owner’s competitors.

Inadvertent exchange versus energy imbalance: Taken together, Version 0 reliability standards and NAESB business practices provide for return-in-kind treatment of inadvertent interchange among control areas;²⁴ at the same time, non-control area utilities are subject under the OATT to paying the higher of 110% of incremental cost or \$100/MWh for under-deliveries outside a narrow 1.5% or 2 MW bandwidth, with over-deliveries compensated at 90% of decremental costs. These penalties unduly burden non-control area utilities who compete at wholesale and retail with the surrounding control area utility, while providing a windfall to the control area operator.

The severity of the competitive impact of this disparate treatment of control area and non-control area utilities was graphically demonstrated by an example TAPS submitted of a wind farm that was shared by a control area and non-control area utility.²⁵

²³ The NERC Long-Term AFC/ATC Task Force (at 3) summarized the wide variations it found on all aspects of the ATC calculation, with some transmission providers starting with TTC, others deriving it from ATC, and some not using it at all. Its finding (*id.*) that “Nearly all use TRM” confirms that something fundamentally is wrong with this picture. If TRM is required for reliability, then *all* transmission providers should reserve it, not “nearly all.”

²⁴ See NERC Standard BAL-006-0 - Inadvertent Interchange, dated August 8, 2005, available at ftp://www.nerc.com/pub/sys/all_updl/standards/rs/BAL-006-0.pdf and NAESB WEQ Inadvertent Interchange Payback Standard - WEQBPS - 005-000, dated January 1, 2005 and corrected March 25, 2005, available at http://www.naesb.org/pdf2/weq_bklet_011505_iip_mc.pdf (last visited Oct. 7, 2005). In its June 24, 2005 Comments in *Standards for Business Practices and Communications Protocols for Public Utilities*, Docket No. RM05-5-000, NERC asked for transfer to NERC of certain NAESB business practice standards on inadvertent energy in-kind payback; the Commission has not yet acted on the NAESB standards.

²⁵ See Pre-Technical Conference Comments of the Transmission Access Policy Study Group, *Assessing the State of Wind Energy in Wholesale Electricity Markets*, Docket No. AD04-13, dated November 12, 2004 and corrected December 23, 2004. TAPS recognizes that in the Commission’s wind imbalance NOPR, *Imbalance Provisions for Intermittent Resources*, Docket No. RM05-10, 70 Fed. Reg. 21,349 (Apr. 26, 2005), the Commission proposed a kinder, gentler regime for generator imbalances associated with intermittent sources. However, the NOPR treated TAPS’s issue regarding discrimination between control area and non-control-area utilities as beyond the scope of the proceeding, a determination TAPS challenged in its May 26, 2005 Comments in Docket No. RM05-10. See also Bruce W. Radford, *Yet Another Subsidy for Wind?*, *Public Utilities Fortnightly*, Aug. 2005, at 19 (noting the Commission’s failure to address load

Despite the finding in the NOPR leading up to Order 2000 (FERC Stat. & Regs. ¶ 32,541, at 33,746-47 (1999)) that it is discriminatory to penalize customers for imbalances while allowing control area operators to draw on inadvertent accounts and pay back those imbalances in kind, which finding was confirmed in Order 2000,²⁶ this difference in treatment persists.

While the non-control area utility side of the equation is solely in FERC's hands, the control area side is in the hands of NERC and NAESB, whose memberships are apparently unable to agree on an alternative.²⁷ TAPS recently wrote NERC and NAESB asking that the discrimination be addressed or referred to FERC.²⁸ As the correspondence shows, NERC views its role as ensuring that NERC standards do not unduly discriminate among the entities to which they apply (*i.e.*, as among all balancing authorities), and concludes that NERC cannot ensure that the standards for balancing authorities are comparable to the treatment of others under tariffs. In contrast, this

imbalances while proposing to address generation imbalances attributable to the same weather variations). The Commission is plainly obliged to remedy that palpable discrimination. *See New York v. FERC*, 535 U.S. 1, 27 (2002).

²⁶ *See Regional Transmission Organizations*, Order 2000, FERC Stat. & Regs. ¶ 31,089, at 31,142 (1999): "In the NOPR, we noted that unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. We conclude that control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory."

²⁷ After 27 months of deliberations, NAESB's Inadvertent Interchange Payback Task Force ("IIPTF") recommended no change in the repayment in kind treatment of control area imbalances, concluding in its July 19 final report (at 5): "With the lack of industry direction for a new 'inadvertent interchange payback' standard the IIPTF has inferred that the industry is satisfied with the requirements within the current NAESB Version 0 Inadvertent Interchange Business Practice Standard." The report is available at http://www.naesb.org/pdf2/weq_iiptf081905a1.doc. From TAPS's perspective, IIPTF's inference that the "industry is satisfied" with the status quo is plainly wrong.

²⁸ *See* TAPS' July 22, 2005 letter to NERC and NAESB; NERC's August 9, 2005 response; and TAPS August 29 reply, all of which are attached hereto. We understand that NAESB is having the IIPTF complete its report, which will be subject to industry comment and then Wholesale Electric Quadrant Executive Committee action at its November meeting. *See also* TAPS July 1, 2005 Comments in

Commission must evaluate a standard's effect on competition in the context of how the standard works together with FERC tariffs, to ensure that the resulting regimen does not unfairly burden one set of competitors while favoring others.

Advantages afforded control areas: In Order Nos. 2000 and 2000-A, the Commission recognized that the performance of control area functions, like the operation of transmission facilities, raises information-disparity issues and creates opportunities for discrimination. It recognized that market participant's operating control areas "have unequal access to commercially sensitive information" and "could use this knowledge of their competitors' schedules and transactions to gain an unfair competitive advantage in the energy markets." Order No. 2000 at 31,104.²⁹ The Commission also recognized the continuing need for standards of conduct in addressing a control area operator's request for relief from transmission provider standards of conduct in light of transmission divestiture.³⁰ While waivers are appropriate for small control areas where the competitive significance is limited,³¹ reliability standards that afford control areas (balancing authorities under the NERC functional model) information and other advantages over other competitors require Commission scrutiny to ensure that they are the least anticompetitive solution to a reliability concern.

Standards for Business Practices and Communications Protocols for Public Utilities, Docket No. RM05-5.

²⁹ To address this situation, Order No. 2000 initially required RTOs "or any entities that operate control areas within the RTO's region that require access to commercially sensitive information to sign agreements that separate reliability personnel and the relevant information they receive from their *wholesale* merchant personnel." *Id.* (emphasis added). On rehearing, the Commission extended the requirement to cover retail merchant personnel as well. In doing so, the Commission explained that it "share[d] TAPS concerns that, when the retail merchant function is purchasing wholesale power, it is participating in the wholesale market and should not be privy to commercially sensitive information that would give it a competitive advantage over other purchasers of wholesale power." Order No. 2000-A at 31,373.

³⁰ *American Transmission Company LLC, Wisconsin Electric. Power Co.*, 98 F.E.R.C. ¶ 61,329 (2002); *American. Transmission Co. LLC, Wisconsin Electric. Power Co.*, 101 F.E.R.C. ¶ 61,027 (2002).

More fundamentally, the Commission needs to examine closely the extent to which the NERC functional model permits vertically-integrated utilities to perform competitively-sensitive security coordinator (now reliability coordinator) functions, which include the authority to cut competitors' transactions. The Commission should take such steps (including requiring independent security coordinators) as may be necessary to ensure that competition is not adversely affected. All changes to the NERC functional model that expand the authority of vertically-integrated utilities similarly require scrutiny for competitive effects.

5. (¶ 54) [T]he Commission seeks comment on whether the Commission has authority to void a previously accepted Reliability Standard. If the Commission has such authority, is it beneficial to have such a provision in the Commission's regulations?

The Commission has express authority to require the ERO to modify a previously-accepted reliability standard. *See* Section 215(d)(5). Congress' failure to provide the Commission with authority to void such standards makes sense given the international nature of the ERO, and the gap that would be created by voiding an existing standard before the replacement standard is in place.

6. (¶ 55) Section 215(d) of the FPA and proposed regulation section 38.4 provide that the Commission may approve a proposed Reliability Standard or modification to a proposed Reliability Standard if it determines that the standard is "just, reasonable, not unduly discriminatory or preferential, and in the public interest." The Commission seeks comment on how this standard should be applied in the context of reviewing proposed Reliability Standards.

Congress's use of the core FPA terms of "just, reasonable, not unduly discriminatory or preferential, and in the public interest" is no accident. These standards should be applied consistent with the case law that has developed during the Act's 70-

³¹ *See e.g., MISO*, 105 F.E.R.C. ¶ 61,145 at P 35 and 51.

year history, while recognizing the reliability purpose of Section 215. Particularly with passage of the legislation, the public interest must be read to encompass the interest in a reliable, secure grid. In light of this well-developed body of case law, the Final Rule need not and indeed, should not, attempt to define these core FPA terms.

7. (¶ 56) We note that the bilateral principles specify that membership in the ERO should not be a condition for participation in the ERO's reliability development process. We seek comments on whether membership in the ERO or a Regional Entity should not be a condition for participation in the ERO's or a Regional Entity's standards development processes.

TAPS agrees with the Bilateral Principles that membership should not be a condition for participation in the standards development process. While membership-related voting rights for ERO governance purposes could facilitate greater commitment and help populate the many committees and task forces that must be filled with volunteers, membership dues should be kept to a nominal amount, consistent with the requirement for funding on a equitable basis among end users (*i.e.*, net energy for load).

8. (¶ 63) The Commission seeks comment on this proposal [regarding non-public procedures for enforcement matters involving a cybersecurity incident] and, in addition, seeks comment on (1) whether the proposal provides sufficient due process and (2) the identification of other specific events that should be subject to non-public hearing procedures.

As noted in Part A.4 above, TAPS urges caution in the adoption of non-public procedures for cybersecurity enforcement matters. Complete secrecy regarding cybersecurity incidents runs contrary to basic due process principles. The 6th Amendment states that “[i]n all criminal prosecutions, the accused shall enjoy the right to a speedy and public trial....” Although an agency proceeding, rather than a criminal prosecution, is at issue here, the concept of a *public* trial is a key part of American due process. On its surface, the right to a public trial protects the accused, an important consideration which is itself sufficient criticism of entirely non-public proceedings for

cybersecurity incidents. But the right also protects the public, who have a right to know as much as possible about what their government is doing. *See also* the NERC Board's June 15, 2004 Guidelines for Reporting and Disclosure, as quoted in response to Question 2 above, which recognize the importance of transparency.

We are emphatically not seeking public disclosure of information that endangers our national security. However, we are concerned that an across-the-board ban goes too far. The fact that a cybersecurity incident has occurred at a particular facility, or with the involvement of a particular contractor, is something in which the public has an interest.

9. (¶ 71) (1) What is the appropriate appeals process, if any, of an ERO or Regional Entity decision to impose a penalty? Would it be appropriate for the ERO or a Regional Entity with delegated enforcement authority to adopt enforcement, penalty and appeals processes similar to the SRO processes discussed above? Should appeals within the ERO be allowed before appeal to the Commission; should appeal of a penalty imposed by a Regional Entity be taken through the Regional Entity itself, with further appeal to the Commission; or should the appeal be through the ERO in the first instance, then to the Commission?

As NERC is suggesting in its comments, after an initial finding of violation, appeals should be available first at the RE level and then at the ERO level. An appeals process at the RE level permits review by those with most knowledge of the regional system. Further opportunity for review by the ERO is essential to enable the ERO to ensure consistency of interpretation and enforcement of its standards, as provided for in the Bilateral Principles. It is also inherent in the statutory concept of delegation — the ERO remains responsible.

Providing for review at the ERO level, instead of just this Commission, is consistent with the procedures for enforcement actions by the New York Stock

Exchange³² and NYMEX.³³ Providing for internal RE and ERO appeal processes is also consistent with the Bilateral Principles.

10. (¶ 71) (2) Should the Commission approve a penalty range or guidelines before the ERO can levy any penalty or sanction for violations, and, if so, should the penalty range or guidelines for a violation be submitted for Commission approval at the same time that the corresponding Reliability Standard is submitted to the Commission for approval?

To facilitate consistent enforcement of the standard, as provided in the Bilateral Principles, a meaningful penalty range or guidelines should be included in the standard itself. This same result could be achieved by establishing a separate penalty scale and specifying, in each standard, the ranges applicable to violation of that standard. By specifying the range in the standard, when FERC and the various Canadian regulators approve the standard, they will be approving a range of applicable penalties, increasing the likelihood that “[t]hroughout the ERO, the penalty [will] be similar for a particular violation and set of circumstances, and [will] be the same within an interconnection regardless of where the violation occurred or who set the penalty” as required by the Bilateral Principles. In addition, would-be violators would be put on notice of the consequences of violating the standard, increasing their effectiveness as a deterrent.

11. (¶ 71) (3) Should a single monetary penalty be prescribed for a violation of a particular standard or should a schedule of monetary penalties be prescribed from which to select at the time of an infraction depending upon relevant circumstances

³² See NYSE Rule 476 (decision by hearing panel reviewable by board of directors, subject to further review by the Securities and Exchange Commission). For “minor violations,” the Exchange may impose a fine of not more than \$5,000 without holding a disciplinary proceeding, subject to appeal to the Hearing Board. NYSE Rule 476A(a) and (d). The Exchange may act summarily to suspend or otherwise limit the access of a person under its jurisdiction who has been suspended by another SRO or who in the judgment of the Exchange is, without regard to bad faith, a danger to investors, subject to stay by the SEC. Securities Exchange Act of 1934 §6(d)(3).

³³ Disciplinary proceedings are handled by a Hearing Panel, NYMEX Disciplinary Rules 8.07(B), with the option of appeal to an Appeal Panel, NYMEX Disciplinary Rules 8.17 (http://www.nymex.com/rule_main.aspx?pg=7) (last viewed Oct. 7, 2005). NYMEX actions can be appealed to the CFTC. See 17 C.F.R. §§ 9.1-9.33.

such as the number of repeat offenses or length of time before adequate corrections are made to bring the violator into compliance?

A schedule of penalties applicable to violation of particular standards, with gradations depending on the circumstances, makes sense and is consistent with the legislation. *See* Section 215(e)(6) (“Any penalty imposed under this section shall bear a reasonable relation to the seriousness of the violation and shall take into consideration the efforts of such user, owner, or operator to remedy the violation in a timely manner”). Penalties should be set high enough to deter failures to comply (so that market participants do not make an economic choice not to incur the cost of compliance). However, the schedule should be sufficiently flexible to permit consideration of factors identified by the Justice Department as relevant to the appropriateness of corporate prosecutions, to the extent applicable.³⁴ Such factors include the type of violation, the risk of harm, the pervasiveness of wrongdoing within the corporation, the cooperativeness of the violator (*e.g.*, effective self policing programs, self reporting, remedial actions, early and meaningful cooperation), whether it is a repeat violation, and the sophistication of the violator.

12. (¶ 71) (4) The Commission interprets section 316A of the FPA, as amended by Congress in the Electricity Modernization Act of 2005, as establishing limits on monetary penalties for violation of Reliability Standards that may be imposed by the ERO, Regional Entities and the Commission. The Commission seeks comment on this interpretation.

The penalties that the Commission itself may assess are limited by Section 316A (*i.e.*, \$1 million/day that such violation continues). It is not quite as clear that this section also caps penalties assessed by the ERO itself. However, given the high level of the new

³⁴ *See* “Principles of Federal Prosecution of Business Organizations,” January 20, 2003, by Larry D. Thompson, Deputy Attorney General, at II(A)(1)-(7), available at

cap, it would be prudent for the Commission to apply the Section 316A cap to all penalties, whether assessed by it or the ERO, while reserving for future judgment the question as to the ERO's legal authority to exceed the Section 316A limit. By doing so, the Commission will enhance the ability of the ERO to respond in the event experience demonstrates that \$1 million/day that such violation continues is insufficient to deter violations (or, in the event penalties are used for restitution, to recompense those adversely affected by violations).

13. (¶ 71) (5) Paragraph (d)(1) of proposed section 38.5 provides that the Commission will review a penalty on its own motion, or upon application of the entity that is the subject of the penalty. Should the Commission determine by rulemaking that certain categories of penalties should be automatically subject to Commission review? For example, should penalties above a certain dollar threshold automatically require Commission review?

Reliability could be harmed just as much or more by too lenient penalties, or failure to assess a penalty at all for a violation, as by penalties that are too harsh. *See* Bilateral Principles (“[P]enalties should be sufficient to maintain reliability...”). Yet those too lenient penalties may stay below the radar screen if review proceedings are limited to instances where the violator appeals the penalty.³⁵

Given the legislation's express provision for the Commission to review ERO penalties on its own motion (*see* Section 215(e)(2)) and to assess its own penalties (*see* section 215(e)(3)), those harmed by the violation should have the opportunity to urge the Commission to exercise that review authority and/or to institute its own enforcement action in response to the ERO's failure to act or to act forcefully to address a violation

http://www.usdoj.gov/dag/cftf/corporate_guidelines.htm.

³⁵ As discussed in Part A.2 above, disclosure of all confirmed violations is similarly necessary for accountability.

(through sufficient and effective monetary and non-monetary penalties). The enforcement action taken by the ERO is not a private matter affecting only the violator, but is a matter in which the public, including utilities that may have been affected by the violation, have a strong interest. Information submitted by such entities may bear on the Commission's determination as to whether to exercise its authority to review the ERO's enforcement action or to institute its own enforcement action. Further, third party evidence and arguments may provide an essential counter-weight to a violator's claim that another entity was responsible for the violation, the penalty is too high or, in the case of a non-monetary penalty, inappropriate. In short, a FERC review process in which the public may participate is essential to the integrity of the enforcement process.

Thus, TAPS strongly supports the NOPR's proposal to publicly notice the filing of enforcement actions. *See* proposed § 38.5(d)(4). The proposed notice and hearing procedure provides a better vehicle for the Commission to make informed judgments as to which actions require review than pre-established categories triggering such review.

14. (¶ 71) (6) What types of non-monetary penalties, if any, are appropriate?

In defining non-monetary penalties, the Commission should take care to preserve the ERO's ability to demand compliance and publicly disclose confirmed violations without that being deemed a "penalty" subject to FERC review and a 31-day delay. As discussed in Part A.2 above, enactment of the legislation certainly should not be a step backwards from what NERC can currently do to ensure reliability.

Other self-regulating organizations, such as the New York Stock Exchange, use non-monetary penalties consisting of censure and various forms of exclusion from the

Exchange.³⁶ While the essential nature of electricity may limit application of an exclusion penalty, non-monetary penalties to be considered might include more narrow prohibitions against engaging in certain transactions or even turning over operation of facilities to a more competent and law-abiding party.

15. (¶ 71) (7) Who should receive, and what should be done with monies collected as monetary penalties? Should the monetary penalties collected by the ERO or Regional Entity be used to defray the cost of its enforcement program, or allocated to some other use? Would allowing the ERO or Regional Entity to use penalty money to fund an enforcement program create an appearance of impropriety?

In general, it is reasonable for penalties to be applied to cover the cost to the ERO and REs of overseeing and verifying corrective actions, with moneys left over added to the ERO's general operating fund and noted as revenue in the year-end true up. Use of the penalties to off-set costs and reduce amounts that need to be recovered through the ERO budget limits the appearance of impropriety problem. Crediting the penalties to reduce the costs borne by those in compliance is consistent with Commission precedent. For example, the Commission has ruled that imbalance penalties should be credited exclusively to non-offending customers within the classifications subject to that are subject to them. *See Entergy Services, Inc.*, 109 F.E.R.C. ¶ 61,095 at PP 65-67 (2004); *Carolina Power & Light Co.*, 103 F.E.R.C. ¶ 61,209 at P 25 (2003).

Room should be left to apply all or a portion of the penalty to restitution in cases where the violation of reliability adversely affects identifiable and discrete victims. Not all standards violations will result in economic harm to a set of discernible victims, nor is

³⁶ Constitution of the NYSE, art. IX § 5.

the economic loss to the victim necessarily the same as any economic benefit to the violator. In some cases, however, restitution may be an appropriate penalty.

Earmarking all or part of a penalty for restitution in such cases would be consistent with the disposition of penalties by other SROs. Specifically, NYMEX can order restitution to the injured parties, although neither the Commodity Exchange Act³⁷ nor the CFTC regulations³⁸ specifically mention restitution as a form of penalty available to NYMEX. Nevertheless, based on the general language of the statute and on the recommendation of the CFTC,³⁹ NYMEX rules expressly provide for restitution.⁴⁰

Following the NYMEX model, the ERO and this Commission could include restitution in its interpretation of “appropriate sanctions.” *See* Section 215(c)(2)(C).

16. (¶ 71) (9) The Commission notes that the bilateral principles provide that RTOs and ISOs should not become Regional Entities, and that the Regional Entities should be distinct from the operators of the system, such as RTOs and ISOs. Should the proposed rule mandate this? What are the enforcement implications of an RTO or ISO that is a Regional Entity? Are there ways for an RTO or ISO to adequately separate its enforcement function from its ownership, use or operation of the Bulk-Power System to fully ensure the independence of the enforcement unit? What process should such an enforcement unit follow to insulate itself from its RTO or ISO organization so that it may undertake any enforcement actions that become necessary against the RTO or ISO? How would this comport with the requirements of section 215 of the FPA?

³⁷ Instead it provides: “[a]ny exchange or the Commission if the exchange fails to act, may suspend, expel, or otherwise discipline any person who is a member of that exchange, or deny any person access to the exchange.” 7 U.S.C. § 12c(a)(1).

³⁸ Penalty for this purpose is defined as “any restriction, limitation, censure, fine, expulsion, suspension, revocation, reprimand, cease and desist order, sanction or any other disciplinary action for any amount or of any definite or indefinite period imposed upon any person within the disciplinary jurisdiction of an exchange upon a finding by the disciplinary committee that a violation has been committed or pursuant to the terms of a settlement agreement.” 9 C.F.R. § 8.03(i).

³⁹ *See* “CFTC Releases Rule Enforcement Review of the NYMEX Division of the New York Mercantile Exchange,” news release of Oct. 5, 2000, available at <http://www.cftc.gov/opa/press00/opa4458-00.htm> (last viewed Oct. 7, 2005).

⁴⁰ NYMEX Rule 8.11(K) (http://www.nymex.com/rule_main.aspx?pg=7) (last viewed Oct. 7, 2005).

For the new reliability regimen to be credible, regional entities must be separate from those they are regulating, including RTOs and ISOs, as provided in the Bilateral Principles. RTOs and ISOs are, by definition, operators of the bulk power system. Allowing them to enforce reliability standards against themselves would create a gaping hole in the mandatory reliability standards Congress thought it was enacting. Functionally separating the grid operator function from the reliability function will not suffice. As the Commission found in Order 2000, the mere perception of opportunities for undue discrimination even with functional unbundling “can also impede the development of efficient and competitive electric markets.”⁴¹ Reliability should not be compromised in this manner.

17. (¶ 71) (11) Paragraph (g) of proposed section 38.5 requires that the ERO and all Regional Entities have in place procedures to notify the Commission of all violations and potential violations of Reliability Standards when the ERO or Regional Entity first notifies the user, owner or operator of the violation or potential violation. We seek comment on what confidentiality protections may be needed, particularly with regard to potential violations. For example, the Commission currently maintains confidential protection of other types of enforcement-related investigations pursuant to section 1b or [sic] our regulations, 18 C.F.R. § 1b (2005). Are similar protections needed here?

Confidentiality should be required for potential violations, but “confirmed” violations should be public, in accordance with the June 15, 2004 Guidelines for Reporting and Disclosure, as discussed in Part A.2 above. The Bilateral Principles also require public disclosure of violations. Even where the violation is contested at the ERO level, the filing of the notice of penalty should be public.

⁴¹ See Order 2000 at 31,015; see also August 22, 2005 Federal Trade Commission (“FTC”) comments in *Information Requirements for Available Transfer Capability*, Docket No. RM05-17 at 3-4, 7-8 (continuing to urge structural separation because behavioral rules are unlikely to fully address transmission discrimination concerns).

18. (¶ 77)⁴² With respect to any monetary penalties levied directly by the Commission against the ERO or a Regional Entity for violation of the FPA, should the ERO or a Regional Entity be able to recover such penalties through dues, fees, or other charges?

(¶ 78) Section 215(e)(5) of the FPA provides that, “[t]he Commission may take such action as is necessary or appropriate against the ERO or a Regional Entity to ensure compliance with a Reliability Standard or any Commission order affecting the ERO or Regional Entity.” Since the ERO and Regional Entity provisions of the Electricity Modernization Act of 2005 are modeled on the SRO provisions of the securities law, and under those provisions, the Securities and Exchange Commission can impose monetary and nonmonetary penalties on SRO board members, should the Commission adopt the same approach with respect to the board members of the ERO and Regional Entities?

As discussed in Part A.5 above, monetary penalties do not make sense in the context of a non-profit ERO and/or RE. If levied, they would go into the ERO budget and be borne by consumers.

Penalties against ERO and RE board members make even less sense, because of the need to attract highly qualified individuals. At best, the potential for such penalties would cause ratepayers throughout the country to pay associated insurance costs.

19. (¶ 80) A Regional Entity may also propose Reliability Standards to the ERO, that, if ultimately approved by the Commission, would become regional variances in a specific region. Any such regional variances would be ERO variances, not Regional Entity Reliability Standards, since it would be the ERO, not the Regional Entity, that submits the proposed Reliability Standard to the Commission for its review. The Commission anticipates that any such regional variances would supplement ERO Reliability Standards, not substitute for them. The Commission seeks comment on this interpretation.

TAPS agrees with the Commission’s interpretation. All standards are ERO standards. As noted in Part A.3 above, only the ERO should be able to submit the standards to FERC for review, and thereby make them enforceable.

⁴² TAPS is not responding to the question posed in Paragraph 73 of the NOPR pertaining to INPO. The fact that little information is available to the public from the INPO website itself raises the questions as to whether it is a suitable model for a self-regulating reliability organization, where transparency is crucial.

We envision not regional variances (a word not used in the legislation) but specification in the ERO standard of modified or more particularized standards for application in one or more regions where such differences have a technical basis, *e.g.*, justified by differences in conditions or operations. The presumption should be strongly in favor of uniformity, except in the case where an interconnection-wide RE proposes a standard for application on an interconnection-wide basis. *See* Section 215(d)(2) and (3).

20. (¶ 84) [T]he Commission seeks comment on the following related issues: (1) Should the Commission prescribe a size, scope, or configuration requirement for the Regional Entities? And, if so, what should it be?

The Commission should insist on consistency across an interconnection as to process and in interpretation and enforcement of ERO standards, as TAPS recommends above. This will make issues of RE configuration much less important. REs provide a vehicle for those in a relatively homogeneous area to have input. When the area gets too big, input and participation will be lost. Particularly given the potential for changes to RTO boundaries, the Commission should not prescribe in advance particular RE configurations.

21. (¶ 84) (2) What is the role of the Regional Entities in relationship to the ERO?

(¶ 84) (3) Beyond enforcement and the proposal of Reliability Standards to the ERO, what, if any, additional authority should the Regional Entities be given?

The legislation converts NERC from a bottom up to a top-down organization. As discussed above, the REs' role under the legislation is to propose reliability standards to the ERO and to enforce standards pursuant to a delegation agreement. The REs should be able to continue to perform other activities as agreed by their members, *e.g.*, resource adequacy, especially where, as in MAPP, states in the region have long depended on the

regional reliability council for such functions. However, these additional activities would not be funded through the ERO's regulatory funding mechanism.

22. (¶ 84) (4) Should the ERO be required to submit a standardized form of delegation agreement concurrently with the ERO application that would delineate a uniform relationship between the ERO and all Regional Entities or should delegation agreements be tailored to the individual needs and circumstances of each region and the ERO and submitted for approval as they are executed by the parties?

(¶ 84) (5) To what extent should the ERO, when delegating responsibility to Regional Entities, require uniform processes in matters including, but not limited to, governance, collection of dues and fees, compliance monitoring, and enforcement action procedures?

Delegation agreements should be standardized to the maximum extent possible.

To obtain credibility and for consistency with the Bilateral Principles, the ERO must require uniform and consistent interpretation and enforcement of reliability standards.

Recognizing that there are market structures in some regions and not others, there may need to be some flexibility in the form of the compliance monitoring. However, the procedures once a potential violation is identified should be as uniform as possible, with greater flexibility afforded where an RE is organized on an interconnection-wide basis.

On the other hand, governance does not have to be identical among the regions; the legislation provides for a permissible range of governing bodies (independent boards, balanced stakeholder boards, or a combination of the two). *See* Section 215(e)(4).

As for dues and fees, funding for RE activities necessary and appropriate to meet its delegated responsibilities should be through the ERO budget process, subject to ERO and FERC review. Further, the requirement in the legislation and Bilateral Principles of equitable allocation among all end users, *i.e.*, on a net energy for load basis, must be met.

23. (¶ 84) (6) What role, if any, should the ERO play in the approval or appeal of an enforcement action undertaken by a Regional Entity?

See Part A.3 and Part B, Response to Question 9 (¶ 71) (1).

24. (¶ 84) (7) What, if any, responsibility or involvement should the ERO have with regard to the funding of the Regional Entities?

The ERO should review and include in its budget the budgets for RE activities necessary and appropriate to fulfill their responsibilities under the delegation agreement.

25. (¶ 84) (9) Should the Commission set the standard by which Regional Entity applications to the ERO will be reviewed or should the ERO be allowed to determine this standard? Given that section 215(e)(4) of the FPA requires that the ERO and the Commission shall rebuttably presume that a proposal for a Regional Entity organized on an Interconnection-wide basis promotes effective and efficient administration of bulk-power reliability, should a higher standard apply to Regional Entities that are not organized on an Interconnection-wide basis? What should the higher standard specify? Should a Regional Entity not organized on an Interconnection-wide basis have the burden to demonstrate that it has appropriate regional scope and configuration to promote effective and efficient administration of Bulk-Power System reliability?

Regional entities not organized on an interconnection-wide basis have the burden to demonstrate that their configuration promotes efficient administration of the bulk power system reliability. For interconnection-wide entities, that particular requirement for an appropriate delegation is presumed, subject to rebuttal. The ERO's standards for assessing proposed delegations must be consistent with the legislation. See Section 215(e)(4).

26. (¶ 84) (10) Paragraph (f) of section 38.7 requires a Regional Entity approved by the Commission to periodically submit to the Commission an application to be re-approved as a Regional Entity. We seek comments on what would constitute a reasonable length of time for such periodic re-approval to be effective. For example, is a five-year approval period appropriate? How far in advance should a Regional Entity be required to submit its application for re-approval before its current approval period expires? What role, if any, should the ERO have in the re-approval process? Would the ERO have to resubmit a delegation agreement?

TAPS supports recertification every six years, consistent with NERC's

Comments.

27. (¶ 103) In addition to comments on the proposed ERO funding regulations, the Commission asks for comments on the following questions: (1) Should the proposed funding requirements be extended to the Regional Entities?

(¶ 103) (2) The Commission notes the bilateral principles include several funding principles: (a) a principle specifying that net energy for load should be the primary basis upon which the costs of the ERO are assigned and that costs for one region or entity should be directly assigned to that region or entity; (b) a principle specifying that funding mechanisms, budget direction and budget levels should reflect consultations with appropriate stakeholders and authorities in each country; and (c) a principle specifying that the appropriate authorities in each country should be responsible for approving and ensuring cost recovery by the ERO and Regional Entities within their respective jurisdictions in a timely manner. Should the proposed rule address these types of funding-related details or should the ERO and Cross-Border Regional Entities have the discretion to address these matters at a later time?

The RE's funding for delegated responsibilities should go through the ERO and Commission review process. It would make sense for the final rule to address and reflect at least Bilateral Principles (a) and (b), as referenced in the Commission's question.

Respectfully submitted,

/s/ Cynthia S. Bogorad

Robert C. McDiarmid
Cynthia S. Bogorad

Attorneys for
Transmission Access Policy Study
Group

Law Offices of:
Spiegel & McDiarmid
1333 New Hampshire Avenue, NW
Washington, DC 20036
(202) 879-4000

October 7, 2005

Attachments



Web Site ♦
www.tapsgroup.org

July 22, 2005

Executive Committee ♦

Bill Burks, MO
Duane Dahlquist, VA
Harry Dawson, OK
Ronald Earl, IL
Roger Fontes, FL
William Gallagher, VT
Marc Gerken, OH
Raymond Hayward, MN
Thomas Heller, SD
William Leung, NE
Gary Mathis, WI
Jim Pope, CA
Bob Priest, MS
Raj Rao, IN
Roy Thilly, WI
Jesse Tilton III, NC

CONTACTS ♦

Roy Thilly, Chairman
Wisconsin Public Power Inc.
1425 Corporate Center Drive
Sun Prairie, WI 53590
608.834.4500
Fax 608.837.0274
rthilly@wppisys.org

**Robert McDiarmid
Cindy Bogorad**

Spiegel & McDiarmid
1333 New Hampshire Avenue, NW
Washington, DC 20036
202.879.4000
Fax 202.393.2866
robert.mcdiarmid@spiegelmc.com
cynthia.bogorad@spiegelmc.com

Deborah Sliz

Morgan Meguire LLC
1225 I Street, NW
Suite 300
Washington, DC 20005
202.661.6192
Fax 202.661.6182
dsliz@morganmeguire.com

Robert Talley

Talley & Associates
2121 K Street, NW
Suite 650
Washington, DC 20037
202.296.4114
Fax 202.296.2409
Tmg1@erols.com

WEQ Executive Committee
North American Energy
Standards Board
1301 Fannin, Suite 2350
Houston, TX 77002

Michehl R. Gent
President & CEO
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, NJ 08540

Re: Inadvertent Interchange Payback

Dear Mr. Gent and WEQ Executive Committee Members:

I am writing to NERC and NAESB on behalf of the Transmission Access Policy Study Group (TAPS) to request that in future consideration of the treatment of inadvertent energy, an important comparability issue does not get overlooked —*i.e.*, allowing return-in-kind treatment of inadvertent energy among control areas, while non-control area utilities are burdened with punitive imbalance charges.

The TAPS group is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access. TAPS members have been following the progress of NAESB’s Inadvertent Interchange Payback Task Force (IIPTF). We were pleased to see the establishment of the IIPTF in March of 2003 with the goal of developing standards to define the alternatives that may be used to settle inadvertent interchange, particularly the mitigation of the potential financial gain that misuse of the payback-in-kind methodology does not prevent. However, we are disappointed that, after 27 months and the consideration of numerous proposals to replace the current payment-in-kind methodology of settling inadvertent energy accounts between control areas/balancing authorities, the IIPTF was unable to reach agreement on an improved system and so concluded in its June 1 memo discussing Task Force results, that “...none of the proposed solutions... better than the payback-in-kind methodology (as embodied in the NAESB Version 0 Inadvertent Interchange Payback Standard).” The result would leave a clearly discriminatory practice in place. We understand that the final IIPTF report will be considered by WEQ at its November meeting.

We also understand that NERC has asked that NAESB’s Inadvertent Interchange Payback standard (WEQBPS) be transferred to NERC’s and included as a reliability standard, and is drafting a Standards Authorization Requests (SAR) for this standard. (For that reason, NERC on June 24 asked FERC to defer action on NAESB’s proposed Version 0 standard in FERC Docket No. RM05-5-000.) This proposed transfer will also bring aspects of this issue shortly before both WEQ (for action on the SAR) and NERC.

♦ An association of transmission-dependent utilities and other supporters of equal, non-discriminatory transmission access and vigorously competitive wholesale electric markets. TAPS members are located in more than 34 states, including: Alabama. Arizona . California . Colorado . Connecticut . Delaware . Florida . Illinois . Indiana . Iowa . Kansas . Kentucky . Louisiana . Maine . Massachusetts . Michigan . Minnesota . Mississippi . Missouri . Nebraska . New Hampshire . New Mexico . North Carolina . North Dakota . Ohio . Oklahoma . Pennsylvania . South Carolina . South Dakota . Utah . Vermont . Virginia . West Virginia . Wisconsin . Wyoming

Thus, the inadvertent energy payback issue may soon be before NERC and/or WEQ. We ask that such consideration resolve, and not avoid, the fundamental comparability issue, rather than simply perpetuate a flawed and discriminatory system. Specifically, the payback-in-kind methodology for inadvertent energy between control areas is clearly not comparable to the treatment of imbalances experienced by non-control area utilities under FERC's open access tariffs. For non-control area utilities, return-in-kind provisions are typically limited to imbalances within a narrow 1.5% deadband, with under-deliveries beyond the deadband charged \$100/MWh or 110% of incremental cost for under-deliveries (whichever is higher), with payments of 90% of decremental cost for over-deliveries. Payback in kind of inadvertent energy avoids these penalty aspects of the tariff completely. Neither the NERC nor NAESB standard should be designed to create or perpetuate competitive advantages for control area operators. This is important not only to achieve fundamental fairness, but also to avoid creating an obvious additional impediment to reasonable control area consolidation.

Whether through NAESB or NERC, the current discriminatory system of payback-in-kind should be replaced with a methodology that treats all utilities equally. As FERC, in Order 2000, concluded:¹

In the NOPR, we noted that unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. We conclude that control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.

Because much of the nation will not have RTO balancing markets any time soon, it is critical that any policies promote a non-discriminatory system to manage inadvertent energy flows. Therefore, we ask the WEQ Executive Committee to reject the recommendation of the IIPTF and direct the IIPTF to develop a methodology that does not perpetuate what FERC has recognized to be a discriminatory treatment of imbalances. To the extent the issue is transferred to NERC, NERC should do the same. If NERC and/or NAESB cannot deal with this fundamental comparability issue (*e.g.*, because sufficient consensus is not possible), they should clearly inform FERC of this problem, identifying the comparability concern as a tariff issue that should be addressed by FERC.

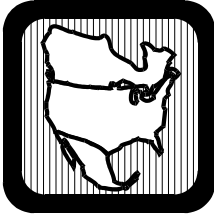
Very truly yours,

A handwritten signature in black ink, appearing to read "Roy Thilly". The signature is fluid and cursive, with the first name "Roy" being more prominent than the last name "Thilly".

Roy Thilly

cc: TAPS Members
Allen Mosher, APPA

¹ *Regional Transmission Organizations*, Order 2000, FERC Stat. & Regs. ¶ 31,089, at 31,142 (1999).



MICHEHL R. GENT
President and CEO

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

August 9, 2005

Mr. Roy Thilly
Chairman
Transmission Access Policy Study Group
Wisconsin Public Power Inc.
1425 Corporate Center Drive
Sun Prairie, Wisconsin 53590

Dear Roy:

Inadvertent Interchange Payback

This is in response to your July 22, 2005 letter to me and the NAESB Wholesale Electric Quadrant regarding the comparability between inadvertent interchange payback and energy imbalance. I understand that you and Don Benjamin talked about this in San Diego last week.

The inadvertent-energy imbalance comparability issue arose frequently within NERC committees soon after the Commission promulgated its *pro forma* tariff. In fact, this is one of the issues that resulted in NERC developing our reliability functional model.

We have debated the characteristics of inadvertent interchange over many years. Specifically:

1. Inadvertent interchange is between a balancing authority and the Interconnection, not between two individual balancing authorities. In other words, inadvertent interchange is not a bilateral arrangement.
2. Inadvertent interchange has two forms: 1.) Inadvertent caused by imperfect generation control that we call "primary inadvertent," and 2.) Inadvertent caused by Interconnection frequency error that we call "secondary inadvertent" (the result of other balancing authorities' primary inadvertent). How should the values of these different forms of inadvertent interchange be determined?

Therefore, while inadvertent interchange appears to have many of the attributes of energy imbalance, they are not the same, and I question whether they can be dealt with on the comparable basis that you are suggesting.

A New Jersey Nonprofit Corporation

Phone 609-452-8060 ■ Fax 609-452-9550 ■ URL www.nerc.com

Mr. Roy Thilly
August 9, 2005
Page Two

It appears to me that NERC and NAESB have both worked hard on inadvertent settlement methods, with NAESB's Inadvertent Interchange Payback Task Force delving into these concepts further than any group we're aware of. Despite the considerable discussions by industry experts, including economists, the IIPTF realized the practical hurdles of calculating Interconnection market prices and values for frequency response couldn't be crossed. Don explained this at the Stakeholders Committee meeting.

NERC is committed to ensure that our standards do not unduly discriminate among the responsible entities to which those standards apply. Standards that apply to balancing authorities must apply comparably to all balancing authorities. However, NERC cannot ensure that standards that apply to balancing authorities will be economically comparable to tariff rules or other protocols that apply to other transmission customers such as generators or load-serving entities, and that NERC has no influence over.

Roy, I believe NERC and NAESB have thoroughly debated inadvertent payback possibilities over many years. We believe NAESB should continue to set the on- and off-peak periods and develop whatever financial payback provisions that industry may agree upon in the future. Both NERC and NAESB have very open standards development processes that will welcome your thoughtful insight.

Sincerely,

A handwritten signature in black ink, appearing to read "Michael R. Gaud", with a long horizontal flourish extending to the right.

cc: Allen Mosher, APPA
Rae McQuade, NAESB



Web Site ♦
www.tapsgroup.org

August 29, 2005

Executive Committee ♦

- Bill Burks, MO
- Duane Dahlquist, VA
- Harry Dawson, OK
- Ronald Earl, IL
- Roger Fontes, FL
- William Gallagher, VT
- Marc Gerken, OH
- Raymond Hayward, MN
- Thomas Heller, SD
- William Leung, NE
- Gary Mathis, WI
- Jim Pope, CA
- Bob Priest, MS
- Raj Rao, IN
- Roy Thilly, WI
- Jesse Tilton III, NC

CONTACTS ♦

Roy Thilly, Chairman
 Wisconsin Public Power Inc.
 1425 Corporate Center Drive
 Sun Prairie, WI 53590
 608.834.4500
 Fax 608.837.0274
 rthilly@wppisys.org

**Robert McDiarmid
Cindy Bogorad**

Spiegel & McDiarmid
 1333 New Hampshire Avenue, NW
 Washington, DC 20036
 202.879.4000
 Fax 202.393.2866
 robert.mcdiarmid@spiegelmc.com
 cynthia.bogorad@spiegelmc.com

Deborah Sliz

Morgan Meguire LLC
 1225 I Street, NW
 Suite 300
 Washington, DC 20005
 202.661.6192
 Fax 202.661.6182
 dsliz@morganmeguire.com

Robert Talley

Talley & Associates
 2121 K Street, NW
 Suite 650
 Washington, DC 20037
 202.296.4114
 Fax 202.296.2409
 Tmg1@erols.com

Michehl R. Gent
 President & CEO
 North American Electric Reliability Council
 116-390 Village Boulevard
 Princeton, NJ 08540

Re: Inadvertent Interchange Payback

Dear Mike:

Thank you for your August 8 response to my July 22 letter, which raised what TAPS members consider to be a fundamental comparability issue.

In our view, inadvertent and imbalance must be treated comparably. In contrast, based on the observation that inadvertent energy is not a bilateral arrangement and takes two forms—primary and secondary—your letter concludes that inadvertent energy is not the same as imbalance and questions whether they can be dealt with on a comparable basis.

In fact, all inadvertent interchange and imbalance energy stem from primary inadvertent. Primary inadvertent is caused by imperfect generation control within a balancing authority. Where a balancing authority is the only entity within its area, its own energy imbalance is its primary inadvertent. Where there is also a TDU within the balancing authority's area, the primary inadvertent is the net of the combined imbalances of the TDU and the balancing authority. While balancing authorities include a calculation for secondary inadvertent based on interconnection frequency, secondary inadvertent simply reflects the impact of primary inadvertent from other balancing authorities.

Providing for in-kind payback for balancing authorities at the same time monetary penalties are imposed for TDU imbalances results in financially non-comparable treatment of the same conduct: imperfect generation control within a control area. Balancing authorities' imbalances are exempt from penalties, while the same imbalances for the TDUs in its area are not, even though the TDUs' imbalances may actually offset the balancing authority's imbalance and so reduce the balancing area's primary inadvertent. The TDU should pay the cost of balancing service, but it should not be penalized when the balancing authority is not penalized for the same conduct. Similarly, the fact that inadvertent energy is not a bilateral arrangement does not justify use of a simple, non-punitive return-in-kind treatment for inadvertent energy while, for tariff customers within a balancing authority, similar imbalances are subject to significant penalties.

♦ An association of transmission-dependent utilities and other supporters of equal, non-discriminatory transmission access and vigorously competitive wholesale electric markets. TAPS members are located in more than 34 states, including: Alabama. Arizona . California . Colorado . Connecticut . Delaware . Florida . Illinois . Indiana . Iowa . Kansas . Kentucky . Louisiana . Maine . Massachusetts . Michigan . Minnesota . Mississippi . Missouri . Nebraska . New Hampshire . New Mexico . North Carolina . North Dakota . Ohio . Oklahoma . Pennsylvania . South Carolina . South Dakota . Utah . Vermont . Virginia . West Virginia . Wisconsin . Wyoming

Michehl R. Gent
August 2, 2005
Page Two.

Your letter narrowly defines NERC's job as ensuring that NERC standards do not unduly discriminate among the entities to which they apply (i.e., as among all balancing authorities), and concludes that NERC cannot ensure that the standards for balancing authorities are comparable to the treatment of others under tariffs. In contrast, we believe that NERC should not turn a blind eye to fundamental comparability issues when formulating its standards and allow its standards to perpetuate or create obvious discrimination that is not required for technical reliability-based reasons.

We also do not believe NAESB is performing its role if it adopts business standards that discriminate against a minority by reinforcing a clearly non-comparable flow of dollars – market participants subjected to substantially different financial outcomes for substantially identical behavior depending on whether they are balancing authorities. Also, based on discussions with TAPS members who participated in the process, we do not believe it was “practical hurdles ... [that] couldn't be crossed” that caused NAESB's IIPTF to recommend no change, but rather a lack of consensus; the IIPTF's July 19 final report concludes (at 5): “With the lack of industry direction for a new ‘inadvertent interchange payback’ standard the IIPTF has inferred that the industry is satisfied with the requirements within the current NAESB Version 0 Inadvertent Interchange Business Practice Standard.” From our perspective, IIPTF's inference that the “industry is satisfied” with the status quo is wrong.

Thus, we reiterate our request that NERC and NAESB address this comparability issue. However, as requested in my July 22 letter, if NERC and NAESB cannot deal with this fundamental comparability issue (because sufficient consensus is not possible), each organization should clearly inform FERC of this problem, identifying the comparability concern that has been raised as a tariff issue that should be addressed by FERC.

Sincerely,

A handwritten signature in black ink that reads "Roy Thilly". The signature is written in a cursive, slightly slanted style.

Roy Thilly
TAPS Chair

cc: NAESB WEQ Executive Committee
TAPS Members
Allen Mosher, APPA