UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Wholesale Competition in Regions with Organized Electric Markets	Docket Nos. RM07-19-000 and AD07-7-000

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

The Transmission Access Policy Study Group ("TAPS") welcomes the opportunity to comment on the February 22, 2008 Notice of Proposed Rulemaking ("NOPR").[1] As transmission-dependent utilities in more than 30 states,[2] TAPS has long advocated that the Commission take steps to reform RTOs to make them more responsive and accountable to customers that depend upon them for reliable, affordable service, to contain and reduce RTO costs, and to otherwise ensure that RTOs produce the lowest possible reasonable rates which the Federal Power Act ("FPA") requires, as reflected in our comments[3] on the Advanced Notice of Proposed Rulemaking ("ANOPR").[4]

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[1] Wholesale Competition in Regions with Organized Electric Markets, Notice of Proposed Rulemaking, 73 Fed. Reg. 12,576 (proposed Mar. 7, 2008), IV F.E.R.C. Stat. & Regs. ¶ 32,628 (to be codified at 18 C.F.R. pt. 35).

[2] 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; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric Co.; Massachusetts Municipal Wholesale Electric Company; Missouri River Energy Services; Municipal Energy Agency of Nebraska; Northern California Power Agency; and Southern Minnesota Municipal Power Agency.

[3] Comments of the Transmission Access Policy Study Group (Sept. 14, 2007), *available at* eLibrary, Accession No. 20070914-5137 ("TAPS ANOPR Comments").

[4] Wholesale Competition in Regions with Organized Electric Markets, Advanced Notice of Proposed Rulemaking, 72 Fed. Reg. 36,276 (proposed July 2, 2007), [2004-2007 Proposed Regs.] F.E.R.C. Stat. & Regs. ¶ 32,617, *comment period extended*, 72 Fed. Reg. 44,437 (Aug. 8, 2007).

The NOPR largely reaffirms the focus and direction taken by the ANOPR.[5] As the Commission moves toward issuing a final rule, TAPS asks the Commission to adjust its proposals as summarized here and detailed below to ensure that RTOs and their market rules are structured to produce just, reasonable and not unduly discriminatory rates that are consistent with the FPA's consumer protection mandate:

Demand Response:

- TAPS generally supports the NOPR's proposal to require RTOs to accept ancillary service bids from demand response resources, provided that the demand response resource meets the RTO-specific technical requirements for such services consistent with mandatory reliability standards. To achieve the intended purposes, the definition of demand response should be clarified to include retail and wholesale behind-the-meter generation.

- TAPS supports the NOPR's proposal to eliminate deviation charges for reducing physical load on the RTO during system emergencies, but opposes both elimination of such charges absent emergencies, and extending the waiver of deviation charges to virtual bidders.

- Commission efforts to promote demand response through aggregators of retail customers ("ARCs") should respect and support existing, effective LSE demand response programs, which provide significant value to consumers that third party ARCs are less able to provide – by integration with the LSE's planning process (avoiding costly peak period generation and reducing reserve obligations).

- To avoid unduly burdening hundreds of municipal systems in RTO regions, the Commission should revise its ARC proposal so that RTOs would be required to accept ARC bids only where the relevant electric retail regulatory authority permits such third party demand response aggregation, and invite such regulatory authorities to contact the RTO to provide notification of such permission. At minimum, any affirmative regulatory action requirement should be restricted to systems above the 4 million MWh Regulatory Fairness Act threshold.

- Given the inability of RTOs, the relevant electric retail regulatory authorities, and affected LSEs to track which retail customers are being aggregated by a particular ARC, the burden should fall on the ARC to identify the retail load being aggregated and to certify that aggregation of demand response for such retail load is permitted (in the same way network customers must provide certification to support designation of

[5] TAPS believes that American Public Power Association has raised serious issues about the operation and impact of RTO markets that merit Commission concern and attention.

network resources). Failure to provide an accurate certification or submission of a bid that includes retail load for which no permission has been granted for third-party aggregation should be a tariff violation.

- The Commission should focus on identifying and addressing other barriers to demand response in RTO-run markets. It should adopt a process that involves retail regulatory authorities and the LSEs that serve retail customers to identify, for each organized market, the specific market rules that impede, or that should be adopted to promote, demand response.

- The necessity of "empirical proof" that there is competition sufficient to yield just and reasonable prices, *Farmers Union Central Exchange, Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984), requires the Commission to strengthen the factual showing that RTOs must make regarding scarcity pricing proposals to include:

    - Specific competitive analyses of market power risks during scarcity conditions;

    - Measures of whether demand response in the RTO region, in fact, mitigates market power;

    - Examination of the incentive and ability to withhold demand response to exercise market power, especially by market participants with generation;

    - Demonstration that the RTO's market mitigation measures target market power under scarcity conditions and are effective in doing so;

    - A determination that there is enough demand response, after considering its use for capacity reserves and ancillary services, to restrain prices during scarcity; and

    - Statistics on experienced and expected scarcity conditions to ensure that such conditions are rare.

- So that it does not preclude beneficial demand response programs, proposed § 35.28(g)(1)(iv)(A) should be modified to read: "Commission-approved ISOs and RTOs must modify their market rules to allow (1) the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand or (2) payments to demand response resources. In either case, the rules must ~~so as to~~ maintain reliability while providing sufficient provisions for mitigating market power."

Long-Term Power Contracting

- TAPS does not oppose the NOPR's bulletin board proposal but does not see it as addressing the more fundamental problems that are impeding long-term contracts.

Market Monitoring Policies

- The Commission should adopt the positive proposals aimed at ensuring market monitoring unit ("MMU") independence and should not retreat from the ANOPR's proposal that RTOs include in their tariffs a provision directing the MMU to report to the Commission concerns regarding the adequacy of market data access, resources and personnel. The Commission should also require whistleblower protections for RTO and MMU employees that report suspicious conduct or express concerns about RTO performance.

- MMU contracts and changes in the MMU's status should be filed with FERC to permit Commission and market participant review and comment. Such a requirement does not impose any particular market monitoring structure.

- The Commission should require the independent MMU to report to the board while clarifying that, where an RTO has both an internal market monitor reporting to management and an external market monitor reporting to the board, the external market monitor must have responsibility for the MMU functions specified in the NOPR. Those functions should include a requirement that the MMU assess whether RTO benefits are flowing to consumers and any impediments to their doing so.

- The independent MMU should not be an advocate for proposed RTO rules or market designs but should instead provide objective analysis of any such proposals by the RTO. If the MMU does not administer the tariff provisions for market mitigation, it must still have the resources to allow it to understand RTO market operations as well as if the MMU were administering mitigation.

- While the reduction in the lag for release of market data from six to three months moves in the right direction, the Commission can safely decrease the delay to a week or less. The Commission should also provide for greater market participant access to MMU reporting and information requests.

RTO Responsiveness

- The Commission should move beyond the requirement for posting *a* mission statement which, at the RTO's election, may include *some* purpose, principles, plus a generalized commitment to be responsive to all stakeholders and consumers. The final rule should require each RTO to file a consumer-focused mission that makes *accountable* to consumers for meeting the Federal Power Act's purpose of ensuring that electricity consumers pay the lowest possible reasonable rates for reliable service.

- To preserve the RTO's ability to fulfill its consumer-focused mission, and to avoid watering down Order 2000's governance requirements, the "balance" criterion should be replaced by: "Due consideration of diverse interests, with actions consistent with FPA consumer protection obligations (*i.e.*, provision of reliable service at the lowest possible reasonable rates)."

- The Commission should make clear that it will allow properly structured hybrid boards (that meet the additional restrictions proposed by TAPS) as a means to meet new responsiveness criteria, while satisfying independence. A hybrid board with an independent majority marries the benefits of independent governance with stakeholder input from high-level executives integrated into the decision-making process, thereby combating board isolation and rendering RTO boards less susceptible to capture by management. Advisory committees would not likely receive the same level of commitment from executives and generally is inferior means to achieve responsiveness.

- Instead of merely encouraging RTO management programs that give appropriate weight to stakeholder responsiveness and other goals, the Commission should advance RTO accountability by requiring RTOs to institute a number of measures, including:

  - Benchmarking RTO costs to other RTOs and non-RTO transmission providers;

  - Biennial, independent cost-benefit analyses;

  - RTO cost-benefit analyses of major new rule or market initiatives prior to their adoption;

  - Annual public reporting of, and other mechanisms to hold the RTO accountable for, performance measures that examine (1) success at relieving congestion costs, (2) responses to transmission requests, (3) reliability and outage statistics, and (4) whether RTO transmission planning and expansion targets are met;

  - Tying RTO senior management compensation to consumer-focused performance measures; and

  - Advance stakeholder review of annual RTO budgets, with provision for RTO appeal to the Commission to resolve issues, with meaningful consideration of the stakeholder rejection, *before* the budget takes effect.

I. DEMAND RESPONSE AND PRICING DURING PERIODS OF OPERATING RESERVE SHORTAGES IN ORGANIZED MARKETS

TAPS recognizes and strongly supports the role of demand response in enhancing reliability and reducing cost, *e.g.*, by avoiding construction of generation that is needed only in very few hours of the year.[6] Many TAPS members are actively involved in

[6] For example, in recent years, ISO-NE's load factor has eroded from 67% to 55% (a decline that continues), which creates a need for larger amounts of less frequently utilized peaking capacity. In 2006,

demand response programs and believe there are steps the Commission can take to foster greater use and development of demand response, as discussed below.

TAPS supports the Commission's objectives of facilitating participation of demand response in organized markets. TAPS supports some of the NOPR's proposals, while suggesting modifications to certain others so that they better achieve their intended purpose. However, as to the NOPR's proposals regarding price formation during periods of scarcity, we continue to believe that the Commission is putting the cart before the horse by expecting that clubbing consumers over the head with high prices will inexorably lead to more demand response. Instead, the Commission should first focus on eliminating barriers to demand response and determine whether price and bid caps are, in fact, obstacles to demand response. Relying solely on theory to remove such caps holds real risks of inflicting severe harm on consumers who lack the infrastructure to protect themselves from high prices. If the Commission moves forward, it should do based upon a fully developed factual record, not theoretical conjecture.

A. Ancillary Services Provided by Demand Response Resources

The NOPR (P 56) would:

> obligate each RTO or ISO to accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand response resources (1) are technically capable of providing the ancillary service and meet the necessary technical requirements, and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric

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over 2500 MW of peaking capacity, totaling more than $2 billion of investment, was needed to serve load for less than 60 hours per year. Demand response could diminish ISO-NE's peaking capacity requirements. *See* Connecticut Municipal Electric Energy Cooperative ("CMEEC"); ISO-New England Demand Response Programs: CMEEC Experience, at 2 (2007), which is Attachment B to TAPS ANOPR Comments.

> retail regulatory authority do not permit a retail customer to participate. … In the compliance filing to be submitted within six months of the final rule, the RTO or ISO must adopt reasonable standards necessary for system operators to call on demand response resources, and mechanisms to measure, verify, and ensure compliance with any such standards.

See also Proposed Regulation § 35.28(g)(1)(i). The NOPR also proposes to allow demand response resources to specify limits on the frequency and duration of their services in their bids (*i.e.*, maximum hours of dispatch, maximum times per day, and maximum amount of energy required on a daily or weekly basis), and asks whether these new parameters should be available for all bids, and not just ancillary services. P 62. It states that these new parameters "must not have the effect of creating an undue preference for demand response resources vis-à-vis other resources." P 64.

Subject to the discussion in Part I.C below (seeking modification of the "unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate" proviso), TAPS generally supports the NOPR's proposal to require RTOs to accept ancillary service bids from demand response resources, provided that the demand response resource meets the RTO-specific technical requirements for such services consistent with mandatory reliability standards. Because such services support the grid's reliability, there should be no watering down of technical requirements simply to open reserves markets to demand resources.

TAPS also supports the NOPR's proposal *not* to require adoption of a competitive bidding process where one was not previously utilized. P 58. Not all RTOs have competitive ancillary services markets. Even those that have such markets do not necessarily encompass all ancillary services.[7] Particularly given the severe market power problems that may be unleashed by such markets,[8] the final rule should adhere to this position, and refrain from forcing the hands of individual RTOs, and the stakeholders and states in the region, on the fundamental question of whether to rely on ancillary service markets, rather than cost-based provision of ancillary services.

TAPS also supports the NOPR's proposal to allow demand response resources to specify limits on the frequency and duration of their bids to provide ancillary service. P 62. Such additional parameters would further the ability of demand response to participate (*e.g.*, by accommodating existing retail contracts and retail customer restrictions that differ from generator operating limits). TAPS would not recommend making those new parameters available for other resources. While we appreciate the Commission's desire to avoid granting an undue preference to demand response resources (P 64), existing bidding parameters afford ample flexibility for generating resources, and we are concerned about the unintended consequences (*e.g.*, new opportunities for gaming) of automatically extending to generators parameters crafted to meet the characteristics and limitations of demand response resources.

TAPS questions whether the regulatory language, as drafted, will operate as intended. The definition of demand response[9] and by extension, demand response

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[7] *E.g.*, the Midwest ISO's recently conditionally approved Ancillary Service Market does not include reactive power and voltage control. It is not clear that demand response can supply that service in any event.

[8] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,172, P 54 (2008); PJM Interconnection, Inc., 2007 State of the Market Report, Section 6 – Ancillary Service Markets, at 276, 278 (Mar. 11, 2008) *available at* http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2.pdf.

[9] "*Demand response* means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." Proposed Regulation § 35.28(b)(4).

resource,[10] appears to exclude some resources capable of contributing to ancillary service markets as demand response resources. For example, wholesale and retail "behind-the-meter generation" can perform as a demand response resource in ancillary service markets. The Commission recently approved the participation of such resources as demand response resources in the Midwest ISO's new ancillary service market.[11] The regulatory language should be clarified to include retail and wholesale behind-the-meter generation. At a minimum, the preamble should make clear that no such exclusion was intended.

Finally, TAPS notes the omission of reliability-based demand response from the regulatory definition. While that may be appropriate given the definition's limited purpose of identifying the demand response bids an RTO must accept, TAPS is concerned that the Commission not lose sight of the important role performed by reliability-based demand response resources – that reduce demand not in response to "an increase in the price of electric energy or to incentive payments," Proposed Regulation § 35.28(b)(4), but rather when called upon to curtail pursuant to the reliability-based terms of tariffs and service agreements that provide the customer longer-term benefits (*e.g.*, a year-round reduction in demand charges).

B. Removal of Deviation Charges

TAPS supports the NOPR's proposal that RTOs with day-ahead and real-time markets "may not assess a charge to a purchaser of electric energy in its day-ahead market for purchasing less power in the real-time market during a real-time market period

[10] "*Demand response resource* means a resource capable of providing demand response." Proposed Regulation § 35.28(b)(5).

[11] *See generally*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,172, P 179 (2008); *cf. Midwest Indep. Transmission Sys. Operator, Inc*., 122 F.E.R.C. ¶ 61,283, P 70 n.76 (2008).

for which the Commission-approved ISO or RTO declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage." Proposed Regulation § 35.28(g)(ii); NOPR at P 72. TAPS agrees that "removal of this deviation charge during a system emergency would remove a disincentive for greater demand response in the real-time market" (NOPR at P 74), and that the associated uplift costs be allocated to all loads (NOPR at P 77). We also agree that "[r]emoval of this disincentive is important during a system emergency when load reduction is needed (and valued) most." P 74.

While the NOPR rightly includes load-serving entities among the "purchaser[s]" for whom deviation charges should be waived when load is decreased in emergencies (NOPR at P 72 n.83), the Commission should clarify that it intends to encompass all forms of demand response that could be activiated to reduce the load served through the RTO market during emergencies. Many demand response programs operate "behind the meter" of the LSE, with a reduction reflected in the wholesale market participant's demand figures. Demand reductions associated with such programs should also be eligible for the deviation charge waiver. *See* Part I.A above (discussing the omission of retail and wholesale behind-the-meter generation from the definition of demand response).

On the other hand, TAPS opposes deviation charge waivers where there is no system emergency, and shares the NOPR's concern "about the resulting possibility of market manipulation and inefficiencies if deviation charges are removed" in other situations. NOPR at P 79. Absent emergencies, accurate scheduling and anti-gaming concerns support imposition of reasonable deviation charges.

In addition, TAPS supports restricting deviation charge waivers to physical load reductions that, in fact, occur and thus provide reliability benefits during the emergency (as the NOPR now proposes), and would oppose extending such waivers to virtual traders, as the NOPR (P 78) suggests the Commission is considering. A virtual trader should not be rewarded for reducing "load," if that reduction exists only on paper and does not provide actual relief for the shortage situation. If the Commission were to reward financial traders that take demand response positions that could not produce actual demand reductions when called upon, the traders could impose millions of dollars on consumers (in uplift costs) without the consumers realizing any benefit. Comparable monetary diversions already occur in FTR markets approved by the Commission where financial traders receive millions of dollars of FTR revenues that they pocket rather than re-invest in needed transmission facilities. The NOPR's suggestion that "virtual purchases *may* enhance reliability by increasing the amount of generation resources available in real time during a system emergency" (*id*., emphasis added) highlights the potential for virtual bids to increase the generation committed in real time in non-emergency situations when it is not needed, thereby needlessly increasing associated revenue sufficiency uplifts costs. The record contains no demonstration that the hypothetical benefits of eliminating the deviation charges for virtual traders would outweigh the harm from reducing the limited disincentives now in place to discourage bidding behavior that imposes significant costs on consumers. As PJM's recent complaint highlights, it cannot be assumed that the actions of virtual traders are benign.[12]

[12] *See* March 7, 2008 Complaint of PJM Interconnection, LLC against Accord Energy LLC, *et al*., at 29 Docket No. EL08-44, alleging market manipulation by (among other things) submission of bids into the day-ahead market "increasing congestion in the day-ahead energy market for their own FTR financial gain," with the effect of "distort[ing] LMPs in the day-ahead energy market resulting in higher prices for

C. Aggregation of Retail Customers

The NOPR "proposes to require RTOs and ISOs to amend their market rules as necessary to permit an ARC [aggregator of retail customers] to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate." P 86. The Commission explains (P 88, emphasis added):

> [W]e clarify that, for the purposes of the ARC part of this rule, the term "relevant electric retail regulatory authority" means the entity that establishes the retail electric prices and any retail competition policies for those customers, such as the city council for a municipal utility or the governing board of a cooperative utility.[92] … Except for circumstances where the laws and regulations of the relevant retail regulatory authority do not permit a retail customer to participate, there is no prohibition on who may be an ARC ….
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> [92] We do not intend to require an RTO or ISO to accept a demand response bid from an ARC that has aggregated the demand responses of retail customers if this is not permitted by laws or regulations of those regulatory entities covered by the term "state regulatory authority" for those retail customers or if the retail customers are served at retail by a "nonregulated electric utility," as these two terms are defined in sections 3(9) and 3(17) of the Public Utility Regulatory Policies Act of 1978 [("PURPA")], 16 U.S.C. §§2602(9), (17) (2000).

The NOPR (P 90) further describes how this requirement would be implemented:

> The market rules do not have to allow bids from an ARC where this is not permitted under the laws or regulations of the relevant electric retail regulatory authority. The RTO or ISO must receive explicit notification from the relevant retail regulatory authority in order to disqualify a bid from an ARC that includes the demand response of that authority's retail customers.

TAPS appreciates the NOPR's recognition of nonregulated electric utilities (which, according to NOPR at P 88 n.92, referencing Section 3(9) of PURPA, means

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energy in several PJM load zones." *Available at* eLibrary, Accession No. 20080307-5190.

"any electric utility other than a State regulated electric utility") as an improvement over the "state laws and regulations" formulation used in the ANOPR. *See* NOPR at P 80. However, TAPS still has significant concerns about the NOPR's proposal. Even assuming the Commission eliminates what we believe to be the unintended suggestion (in footnote 92 and P 90) that an RTOs may elect to accept a demand bid from an ARC even where not permitted by the "relevant electric retail regulatory authority," the proposal would place undue burdens on many, many individual nonregulated electric utilities to take affirmative regulatory actions to maintain their authority (which many would assume is a necessary and implied component of a traditional "obligation to serve") to act as the "aggregator of retail customers" for the retail customers whose requirements they are entrusted to serve with reliable service at reasonable rates. It also presents significant implementation and enforcement challenges.

1. ARCs Are Not the Only or Most Effective Aggregators of Demand Response

The NOPR suggests that Section 1252(f) of Energy Policy Act of 2005 ("EPAct 2005"), 16 U.S.C. § 2642(f) justifies the Commission's proposed encouragement of ARCs at the expense of interfering with LSE-based demand response programs. In describing its proposal with regard to ARC bidding, the NOPR states (P 92 n.93, emphasis added):

> In particular, this proposal would *not necessarily* require any change to an existing aggregation program that already functions well if the existing program satisfies the proposed criteria. *See* NEPOOL Participants at 12; TAPS at 19-21; Silicon Valley Power at 7-8.

This passage suggests that even "if the existing program satisfies the proposed criteria,"[13] highly productive LSE aggregation programs may be required to change to accommodate ARC-aggregated demand response programs. Such an approach would heighten, rather than eliminate, barriers to effective participation of demand response, contrary to EPAct Section 1252(f).

Many LSEs may have worked out tariffs and contractual arrangements with their largest customers to provide demand response that are quite different from and inconsistent with allowing the customer to receive payment through an RTO market for reducing demand. These programs may provide the customer with demand charge reductions in exchange for permitting the LSE to interrupt it under certain circumstances, *i.e.*, when needed to keep the lights on. The Commission should take care not to trample on these contractual and tariff arrangements, and reliability-based programs.

Examples of LSE-based demand response programs that should be respected include:

- Municipal systems in Connecticut, while representing a small part of total New England load, contribute significantly to New England demand response resources. Approximately 27 MW participates in ISO-NE's load reduction program. Another 29 MW participates as demand response through ISO-NE's emergency generation program where generation sited a retail customer's facility is dispatched during emergencies, thus reducing or eliminating that customer's load from the system. While CMEEC's load is only about 1.5% of ISO-NE's total load, when, ISO-NE called upon CMEEC during its August 6, 2006 "OP-4" emergency, CMEEC's demand response represented over 12% of total demand response in ISO-NE during that event.[14]

[13] It is not clear which "proposed criteria" this sentence intends to reference.

[14] Requirements for participation in the Forward Capacity Market, however, have discouraged the participation of this relatively significant amount of demand response. Out of 10 CMEEC customers representing 27 MW of demand response resources, only one such customer representing only 180 kW of demand response load was able or willing to participate. *See* ISO-New England Demand Response Programs: CMEEC Experience, at 2, Attachment B to TAPS ANOPR Comments.

- In Vermont where there is no retail access, LSEs have nonetheless had the contractual ability to call for load reductions for over 20 years. TAPS member Vermont Public Power Supply Authority has over 10% of its load under such contracts. Another TAPS member in Vermont, Burlington, has about 8 to 10 percent of its load participating in ISO-NE's emergency demand response program.

- TAPS members in Wisconsin have adopted a variety of primarily reliability-focused demand response programs. These includes programs for the LSE to interrupt residential air conditioners, operate back-up generation located at commercial/industrial customer sites, and interrupt commercial/industrial load when customer demand exceeds generation or transmission capacity. In addition to providing relief during emergencies, the programs help LSEs meet reserve requirements and delay the construction or acquisition of new generation. These programs are reflected in tariffs and contracts which, in some cases, provide for a very valuable demand charge credits in exchange for being willing to be interrupted under specified conditions. Such a demand-charge based programs would mesh poorly with an RTO program that rewards demand response through the spot energy market. Significantly, when MISO called a reliability emergency and LSEs responded by contributing close to 3000 MW in demand reductions (*see* ANOPR at P 52 n.52), Wisconsin contributed disproportionately (compared to its share of total load) to that reduction.

- Demand response programs on TAPS member systems in California cover a broad range, including advanced metering that allows retail customers to manage their overall consumption and respond to utility requests for curtailment, air conditioning load interruption, firm load curtailment, and emergency generators at municipal facilities. The programs are largely aimed at providing demand response during emergencies.

Nor is there any reason to assume that ARC-initiated programs will more successfully harness demand response than LSE-created programs. To the contrary, the 2007 FERC Staff Assessment of Demand Response and Advanced Metering (at 7)[15] found load reductions in demand bidding programs of only 4-19% of enrolled demand response resources. It distinguished between "economic" (demand bidding) DR (which is not as effective, *i.e.*, <20% response rate) and "reliability-based" DR (which has a much higher response rate –62% and 83% in the programs reported in the 2007 Staff

[15] *Available at* http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf.

Assessment). Indeed, in the experience of TAPS members, such reliability-based programs have a response rate in excess of 90%.

Further, an LSE can structure its demand response program to maximize the value to all its customers, rather than just the few supplying the demand response. Unlike ARCs, LSEs can integrate their demand response program into their planning, and deliver significant value in avoiding or deferring generation investment. Some TAPS members have avoided purchases of a block of power for the peak season by implementing programs that commit retail customers to interruptions when directed by the LSE. Such LSE may interrupt retail customers proactively to avoid such purchases, rather than simply responding to "scarcity" price signal. For example, to avoid committing to a peak block of power for the summer season, TAPS member CMEEC called on its demand response customers to reduce load even *before* prices reaches "scarcity" levels.[16] LSEs can get additional value from integrating demand response into their planning by avoiding the need to carry reserves for interruptible load.[17]

In contrast, if the demand response of these same large customers were instead harnessed by a third-party ARC (in response to RTO price signals), the LSE would need to include those customers' full loads in its planning as firm and carry reserves to meet that load. If the LSE no longer controlled that demand response, the value to the LSE and its other customers of avoiding peak block generation investments and additional

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[16] *See* ISO-New England Demand Response Programs: CMEEC Experience, at 3, CMEEC Loads and Resources—August 2, 2006 (graph showing that CMEEC called upon its demand response when prices were not much more than $180/MWh, several hours *before* prices climbed to the $1000/MWh level). This presentation is appended to TAPS ANOPR Comments as Attachment B.

[17] For example, under the Midwest ISO's recently conditionally-approved Resource Adequacy Requirement, an LSE may deduct certain demand response resources from the firm load for which it must meet the MISO-established planning reserve margin. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,283 at P 29, n.26.

reserves would be lost. The public interest is not served by undermining such highly valuable LSE-organized demand response programs by establishing a regulatory preference for third-party demand response programs.

Thus, the final rule should be restructured so that the Commission can revise footnote 93 to accurately state that "this proposal would *not* ~~*necessarily*~~ require any change to an existing aggregation program that already functions well." While TAPS appreciates the Commission's desire to promote demand response, existing programs should be respected.

2. The NOPR's ARC Provision Should be Revamped to Avoid Significantly Burdening Many Small Municipal Utilities

As noted, the NOPR proposes to require RTOs to accept ARC bids "unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate" (P 86); to define relevant electric regulatory authority as the "entity that establishes the retail electric prices and any retail competition policies for those customers, such as the city council for a municipal utility or the governing board of a cooperative utility" (P 88); and to require such entity to provide the RTO "explicit notification … in order to disqualify a bid from an ARC that includes the demand response of that authority's retail customers." P 90. The net effect would be to require the city council of each and every municipal entity located in an organized market, regardless of size, to contact the RTO and potentially to go through a legislative process to address an issue likely to be implicitly, but not explicitly, addressed in existing laws and regulations – whether third party ARCs may aggregate the demand response of the municipal's load. TAPS believes that this burden is undue.

To the extent a municipal system does not allow retail competition (*i.e.*, it is not in a retail access state or has opted out of retail competition pursuant to the applicable laws of a retail access state), many would likely presume that the exclusive right and obligation to serve to its citizens and ratepayers with electricity includes the right to aggregate their customers' willingness not to purchase electricity – *i.e.*, to aggregate their demand response. Indeed, the loss of control over their retail customer's demand response could impair the LSE's ability to plan for the load and thereby harness that demand response to reduce the load for which the LSE must plan (*see* Part I.C.1 above). It can also expose an LSE to extra charges, *e.g.*, for failure to accurately schedule, as illustrated by the NOPR's proposal to excuse deviation charges for decreasing load in emergencies (discussed in Part I.B above). If ARC-aggregated load causes a drop in an LSE's load during periods other than when this emergency exception were triggered, the LSE would be subjected to deviation charges if its real-time load was below its day-ahead load. Similarly, an ARC-triggered decrease or increase[18] in an LSE's load could trigger over- and under-scheduling charges under the SPP Energy Imbalance Service tariff.[19]

While many non-retail choice municipal systems likely presume and value the right to aggregate their retail customers' demand response, we expect that few municipal electric systems will have addressed that specific issue in their laws and regulations because third-party ARCs are a new concept. However, the NOPR could be read to require each such municipal system to take legislative or regulatory action specific to the

[18] *E.g.*, at the conclusion of the period when the demand response bid was activated.

[19] *See* Sections 5.3 and 5.4 of Attachment AE to the Southwest Power Pool, FERC Electric Tariff, Fifth Revised Volume No. 1, which subjects LSEs whose load deviates from schedules by more than 4% or 2 MW to such charges in certain circumstances. *Available at* http://www.spp.org/publications/SPP_Tariff.pdf.

third-party ARC issue and to contact the RTO; as proposed, absent such affirmative regulatory action, the RTO would be required to accept ARC bids aggregating demand response from customers within the municipal.

Requiring each such city council of every municipal in an RTO to address the issue through legislation or regulation, even where the municipal does not allow retail access, is a huge undertaking. For example, TAPS member AMP-Ohio includes 122 municipal electric systems in MISO and PJM; TAPS member Indiana Municipal Power Agency serves 51 municipal electric systems in MISO and PJM; TAPS member Wisconsin Public Power Inc. serves 50 municipal electric systems in MISO; and the list goes on. Many of these systems are very small. Getting the city council of each such municipal to address the ARC issue, much less contact the appropriate person in the applicable RTO (with whom the municipal member of a joint action agency may previously have had no direct contact) would be a Herculean task. Nor is the city council necessarily the pertinent regulatory body.[20]

This burden on small utilities is why Congress requires the Commission to make a Regulatory Flexibility Act certification as to the impact on entities whose total electric output does not exceed 4 million MWh. *See* 5 U.S.C. § 601-12; 13 C.F.R. § 121.201.[21]

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[20] Many electric municipal systems have utility boards that set retail rates and other regulatory policies. Municipal members of a joint action agency are often under very long-term full-requirements contracts, which support the joint action agency's bonds and enable them to carry out their assigned power supply and load aggregation functions. Joint action agencies are governed by their members, who sit on their board, which plays a regulatory function by setting the wholesale rates to the municipal members (which comprise the bulk to municipal members' retail rates) and establishing other pertinent policies. The joint action agency is typically the interface with the RTOs, who often have no contact with the individual municipal members.

[21] This same concern is reflected in PURPA's restrictions on "non-regulated electric utility[ies]" (Section 3(9) of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2602(9), *see* NOPR at P 88 n.92) required to investigate and issue a decision on such issues as "whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response

The NOPR (P 291) recognizes this obligation but treats the proposed rule as directly affecting only RTOs, failing to take account of the hundreds of small entities that it proposes to effectively put through this legislative/regulatory process.

TAPS recognizes that the Commission may not want RTOs making assumptions about which systems within the RTO are open to third-party aggregation and which are not. And it may not want to leave that decision to the discretion of utilities that may have views that differ from their state commission.[22]

TAPS suggests that the Commission can achieve its objectives of ensuring that RTOs accept ARC bids where regulators are willing to permit third-party ARCs by replacing the "unless" clause with "if the relevant electric retail regulatory authority permits." The Commission would thus invite relevant electric regulatory authorities to contact the RTO to provide notification of such permission. Absent such explicit notification that permission has been granted, the RTO would presume that an ARC could not lawfully aggregate the affected retail load. This modification would ensure that any relevant electric regulatory authority that wished to allow third-party demand response aggregation could do so, without unduly burdening hundreds of municipals.

At minimum, any affirmative regulatory action requirement should be restricted to systems above the Regulatory Fairness Act threshold. Only systems with a total electric output exceeding 4 million MWh would need to go through the process.[23]

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programs." EPAct Section 1252(b)(3)(i), 16 U.S.C. § 2625(i), amending PURPA § 115. Only non-regulated electric utilities with retail sales of more than 500 million kWh must go through that process. *See* PURPA § 102(a), 16 U.S.C. § 2612(a).

[22] Concerns about a gulf between utilities and their regulators on third party ARC issues should be significantly diminished in the case of municipal utilities and their joint action agencies (which are responsive to and governed by member municipal utilities that sit on their board).

[23] An alternative threshold would be those municipals with retail sales of more than 500 million kWh, as used in PURPA.

Limiting application of the NOPR's proposal in this manner would minimize the burden on small systems associated with the NOPR's explicit notification requirement, consistent with the NOPR's RFA Certification. *See* NOPR at P 291.

3. The Final Rule Should Clarify and Address Other ARC Implementation Issues

The NOPR raises serious implementation issues even beyond the key question of what, if any, action a "relevant electric retail regulatory authority" must take to decline to allow third-party ARCs to aggregate the load for which they are required to plan and provide service.

As an initial matter, the final rule should eliminate the NOPR's (likely inadvertent) suggestion that an RTO may accept the bid of ARCs that aggregate load where not permitted to do so by the "relevant electric retail regulatory authority." *See* NOPR at P 90 & P 88 n.92. RTO tariffs should expressly bar acceptance of such bids.

But how will this tariff provision be enforced? Even assuming the list of LSEs allowing ARCs is clear,[24] neither the RTO nor the "relevant electric retail regulatory authority" is in a position to police whether an ARC has aggregated load of an LSE where not so permitted. It may be difficult, if not impossible, for either to identify whether such improper aggregation is occurring. ARCs will likely not want to publish a list of every retail customer whose demand response is being aggregated. Even if such an ever-changing list were published, LSEs/relevant electric retail regulatory authorities would not necessarily be able to identify the presence of their own customers given multiple names, corporate structures, and locations that may be involved.

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[24] Reversing the "explicit notification" requirement, as suggested in Part I.C.2 above, should help RTOs in that regard.

Given the inability of the LSE/relevant electric retail regulatory authorities to readily track which retail customers are being aggregated by a particular ARC, placing this requirement on such entities is impractical and unfair. Such tracing would also significantly burden RTOs.

In contrast, the ARCs are in the best position to identify the retail load being aggregated and to verify that such aggregation is permitted by the relevant retail electric regulatory authority. ARCs should therefore be required to certify that aggregation of demand response for such retail load is permitted, much like network customers must provide certification to support designation of network resources.

Under Order 890, network customers must attest, for each network resource identified for designation, that (1) the transmission customer owns or has committed to purchase the designated network resource and (2) the designated network resource meets the requirements for designated network resources.[25] Transmission providers must terminate network resource designation requests that do not contain the proper attestation,[26] and designation of a network resource that does *not* meet these criteria is a tariff violation that may be the basis for the assessment of civil penalties.[27] In the same way, an ARC should be required to certify that the retail loads being aggregated are permissibly aggregated by third party aggregators, and submission by an ARC of ineligible demand response bids should be a tariff violation.

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[25] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266, 12,462 (Mar. 15, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,241, P 1521 (to be codified at 18 C.F.R. pts. 35, 37), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,261, *review docketed*, No. 08-1276 (4th Cir. filed Mar. 5, 2008) ("Order 890"); Order 890 OATT § 29.2(viii).

[26] Order 890 at P 1522.

[27] *Id*. P 1523.

D. Possible Future Demand Response Reform

The NOPR (P 95) directs Staff to hold a technical conference to consider: "(1) If there are barriers to comparable treatment of demand response that have not previously been identified and what they are; (2) potential solutions to eliminate any potential barriers to comparable treatment of demand response; (3) appropriate compensation for demand response; and (4) the need for and the ability to standardize terms, practices, rules and procedures associated with demand response, among other things." It also proposes to "require each RTO or ISO to assess and report on the barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction, including those listed above, and to submit its findings and any proposed solutions along with a timeline for implementation to address barriers to the Commission within six months of the Final Rule." *Id.*

TAPS supports these further technical conferences and studies. More generally, TAPS believes it would be more productive, and more consistent with the Commission's statutory mandate, for the Commission to focus its efforts on identifying and removing unnecessary barriers to demand response, rather than assuming that price and bid caps are the problem, and proposing to relax market power mitigation (discussed in Part I.E.1 below). TAPS ANOPR Comments (at 28-29) urged the Commission to adopt a process that involves retail regulatory authorities and the LSEs that serve retail customers to identify, for each organized market, the specific market rules that impede, or that should be adopted to promote, demand response. This approach would move the stakeholder process closer to the retail customers whose "demands" will be a principal factor in the success or failure of demand response programs. It would build upon the Commission's commendable efforts in the NARUC-FERC Collaborative Dialogue on Demand Response (*see* NOPR at P 36). Such approach would build the bridges needed to achieve the state-local-federal coordination and cooperation needed to have a truly effective demand response program, recognizing that whatever the scope of this Commission's jurisdiction policies crucial to the success of Commission initiatives remain subject to state and local control (*e.g.*, retail rates).[28]

E. Market Rules Governing Price Formation During Periods of Operating Reserve Shortage

1. The FPA Requires "Empirical Proof" that Demand Response Suffices to Keep Rates Just and Reasonable

As discussed above, TAPS agrees with a number of the Commission's proposals for removing barriers to demand response. The Commission errs, however, in its diagnoses and remedies regarding scarcity pricing and the potential role of demand response. Fundamentally, the NOPR's proposals suffer from a serious absence of evidence that offer/bid caps limit scarcity pricing and that lifting such caps will attract investment in generation and demand response sufficient to protect consumers from market power.

The Commission observes: "In a competitive market, demand and supply respond to price." NOPR at P 108. The NOPR's proposals focus on price formation during scarcity conditions when additional supply is, at least in the short term,[29] unavailable so that any price response will come from demand. When the Commission is

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[28] "Enhancing coordination of federal and state initiatives on demand response … offers the most promising approach to managing the jurisdictional overlap," Hon. Jon Wellinghoff and David L. Morenoff, *Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation*, 28 Energy L. J. 389, 418 (2007) (italics omitted)

[29] In the long run and depending upon entry conditions, new generation may, in theory, respond to high prices and return them to just and reasonable levels.

relying upon demand to provide the competitive response necessary to keep rates just and reasonable, the FPA's commands still apply. There must be "empirical proof" that "existing competition would ensure that the actual price is just and reasonable." *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486, 1510 (D.C. Cir. 1984). "[U]ndocumented reliance on market forces" is insufficient to satisfy the Commission's regulatory responsibilities." *Id.* at 1508.

The Commission, however, appears willing to move forward relying on undocumented – indeed, theoretical – market forces. It states: "We … do not believe that reforms in this area should be delayed until every barrier to demand response, whether retail or wholesale, technological or regulatory, is identified and addressed." NOPR at P 109. Commissioner Kelly's dissent echoes TAPS's concern that the Commission is putting the cart before the horse:

> I continue to be troubled by the NOPR's proposal in the Market Rules Governing Price Formation During Periods of Operating Reserve Shortage section. This section would attempt to stimulate demand response by allowing RTOs/ISOs to implement scarcity pricing by modifying market power mitigation rules in organized markets, such as raising energy supply offer caps and demand bid caps. I appreciate the efforts made in the NOPR to address market power associated with scarcity pricing and to ensure that there is an adequate record regarding any scarcity pricing proposal, including soliciting the views of each RTO/ISO market monitor on any proposed reform in this area. However, these positive changes in the NOPR proposal have not alleviated my concerns regarding the very real impacts on customers associated with raising energy supply offer caps and demand bid caps in emergency situations.
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> * * *
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> We must never lose sight of the interests of consumers as we engage in this kind of philosophical debate because they

> will be the ones who will lose out if we miscalculate. The necessary generation and demand response infrastructure must be in place prior to allowing energy supply offer caps and demand bid caps to rise or be eliminated. Unfortunately, this is not the case.

NOPR, Commissioner Kelly partial dissent.[30] The Commission's attempt to stimulate demand response through unrestrained scarcity pricing is akin to allowing market-based rates without assurances of the open access transmission necessary for competing supply to restrain prices. Unlike its approach to market-based rates, however, the Commission would unleash market forces without making factual findings that the demand response to necessary restrain prices is ready, willing and able to be called upon.

Indeed, the Commission concedes that it does not yet have the facts to find that demand response levels are sufficient, basing its NOPR proposals on belief and theory.

> We have carefully considered the comments on this issue and continue to *believe* that existing market rules appear to be unjust, unreasonable and unduly discriminatory or preferential during times of scarcity. In particular, they *may* not accurately reflect the true value of energy and, by failing to do so, *may* harm reliability, inhibit demand response, deter new entry of demand response and generation resources and thwart innovation.

NOPR at P 107 (emphasis added). The passage's (and the NOPR's) absence of factual findings is striking.

Moreover, the NOPR's conjectures about expected market response do not reflect TAPS members' day-to-day experiences with wholesale markets. For example, the Commission says: "Furthermore, by artificially capping prices, the price signals necessary to attract new entry by both generation and demand resources are muted and long-term resource adequacy is harmed." NOPR at P 111. This observation fails to

[30] 73 Fed. Reg. 12,617, IV F.E.R.C. Stat. & Regs. ¶ 32,628 at 33,567-68.

confront evidence that high spot market prices do not correlate with entry in RTO markets. Rating agency reports,[31] testimony at Commission technical conferences,[32] and empirical studies all have debunked the assumption that spot market pricing will bring about needed investment in generation and transmission. In *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers*, for example, Synapse Energy Economics analyzed the siting of new generation and the location of generation retirements in PJM and concluded:

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[31] For example, Standard and Poor's July 1, 2004 Report, *Makeover for California's Power Markets*, explains:

> Pricing data associated with hourly nodal prices should provide market signals for use in planning for investment in transmission and new generation. Yet, generators may realize that the benefits will be ephemeral. Once generators build capacity in a load pocket to address transmission congestion issues, prices will likely reach equilibrium levels that could remove the economic incentives created by locational marginal pricing. Therefore, generators may forego developing fixes if their investments might fail to provide them with economic benefits commensurate with development risks throughout the asset's life. The same argument also could be extended to developing transmission.

[32] *See*, *e.g.*, Technical Conference, *Transmission Independence and Investment*, Docket Nos. AD05-5-000 and PL03-1-000, Tr. 37-38 (Larson, Trimaran Capital Partners) (Apr. 22, 2005), *available at* eLibrary, Accession NO. 20050422-4031:

> So with respect to incentives, my issue with incentives as opposed to rate-based treatment is this: That does introduce uncertainty into it and it does increase the rate. If I need to be able to predict say LICAP for the next 20 years in New England, without the rules even being clear to me how it's being done right now, much less in five years, then I'm going to price that into the returns that I require for that type of transmission investment.
>
> On the other hand, if it's been determined that a project is in the interest of ratepayers and that, based upon a regulatory approval proceeding that it is almost certain that, given a rate-based treatment of a certain new asset, that the benefits are going to offset the cost of the allowed return by the new investor, then frankly, I'll invest in that at a much lower required return.
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> It's the predictability of earnings. And the uncertainty is not the uncertainty of earnings in a project right now, at least with respect to the investments that we've considered; it's the uncertainty of there being a project at all.

See also Technical Conference, *Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets*, Docket No. PL04-2-000, Tr. at 149 (Anderson, John Hancock Financial Services) (Feb. 4, 2004), *available at* eLibrary, Accession No. 20040204-0444: "Most capital for power infrastructure is provided by debt markets not equity markets. If you look at capitalization of power assets, as you probably heard this morning, we value stability. We're not in this to make a killing off of spiking peak power prices. We're putting capital into this business in opportunities that we think can provide long term stable reasonable returns and are on the low end of the risk adjusted spectrum." The testimony reflects the reality that LSEs, not to mention generation developers, see today: investors will not fund projects unless they are backed by long-term contracts. Tr. 153 (Baliff, Credit Suisse First Boston Corporation). In the words of one investment banker: "I think the economists like volatility, but the

> We make the following observations of the effect of LMP price signaling as an incentive for new generation construction and retirement decisions in PJM:
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> • Most of the new generation constructed in PJM has not been in the higher priced eastern regions; conversely, a large share of the retirements *has* been in high-priced regions.
>
> • Most of the new generation had been planned and constructed prior to the recent increase in electricity prices and, because it … utilizes mostly gas-burning technology, it is not benefiting from those prices;
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> • Proposed new generation in the PJM queue continues to be disproportionately located in regions outside of the high-priced Eastern zones. In addition, PJM has proposed three new east-west transmission corridors pursuant to the 2005 Energy Policy Act, suggesting that they have perhaps minimal expectation that sufficient generation can or will be built in high priced regions and thus transmission is required for reliability assurance;
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> • LMP price signals do not appear to be providing effective incentives to build and maintain generation where and when it is most needed.[33]

The Commission's contentions about the amount of demand response needed to restrain prices are similarly lacking in reliable evidentiary support. The Commission states that "putting rules in place that allow the fraction of the load currently able to respond can have a very positive effect on the market and help reduce prices for all." NOPR at P 110. In support of its belief, the Commission cites the 2006 FERC Staff Demand Response Assessment that found that "as little as five percent of load responding to price may discipline market prices." NOPR at P 110 n.104. This belief, however, is contradicted by the 2000 study, *Estimating the Opportunities for Market Power in a*

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marketplayers don't." Tr. 262 (Newman, Warburg Pincus).

[33] Synapse Energy Economics, Inc., *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers* at 32 (Feb. 5, 2006) (prepared for American Public Power Association), *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2007-02.APPA.LMP-Electricity-Markets.06-060-Report.pdf.

Deregulated Wisconsin Electricity Market, that concluded that one third of the load in the load in the Wisconsin Upper Michigan Subregion ("WUMS") would have to be dropped to mitigate market power.[34]

As Commissioner Kelly observes in her partial dissent: "[The Commission] must never lose sight of the interests of consumers as we engage in this kind of philosophical debate because they will be the ones who will lose out if we miscalculate."[35] The FPA does not allow the Commission to treat consumers as guinea pigs. Rather, the Commission must ensure a "complete, permanent and effective bond of protection from excessive rates and charges." *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959). If it acts without the requisite empirical proof, the Commission will fail to protect consumers.

2. The Commission Needs to Strengthen the Factual Showing that RTOs Must Make With Respect to Scarcity Pricing Reforms

To its credit, the Commission includes in the NOPR a requirement that "each RTO or ISO proposing to reform or demonstrate the adequacy of its existing market rules in this area must provide an adequate factual record for the Commission to evaluate its proposal," NOPR at P 118, and that RTO "[h]ave provisions for mitigating market power and deterring gaming behavior, including, but not limited to, use of demand resources to discipline bidding behavior to competitive levels during periods of operating reserve

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[34] James Bushnell, Christopher Knittel and Frank Wolak, *Estimating the Opportunities for Market Power in a Deregulated Wisconsin Electricity Market*, at 31-33 (2000) (commissioned by Customers First!, a coalition that includes TAPS members WPPI and Madison Gas and Electric Company, and *available at* http://www.customersfirst.org/pdf/MarketPowerPaper.pdf) looked at demand response in WUMS. It concluded that 4000 MW of load (or 1/3 of the total WUMS load) would have to be dropped to mitigate market power in that highly constrained and concentrated subregion, *id.* at 33. This amount of demand response was term "extremely unrealistic." *Id.*

[35] NOPR at 73 Fed. Reg. 12,617, IV F.E.R.C. Stat. & Regs. ¶ 32,628 at 33,568.

shortages." NOPR at P 119. TAPS is fearful, however, that the Commission's willingness to come this far without empirical support for its reform proposals will mean that it will be less than demanding and rigorous when it comes to assessing RTO compliance filings, especially if an RTO adopts one of the four reform approaches set forth in the NOPR. In light of the Commission's FPA obligations, *see* Part I.E.1 above, the final rule should require that the factual record developed by RTOs include at least the six following analyses.

a) RTOs' market power analyses should specifically analyze true scarcity conditions

While the NOPR's proposals concern price formation under scarcity conditions, the Commission's standards for market-based pricing do not address market power under scarcity conditions. None of the usual metrics – pivotal supplier, market share, and the delivered price test ("DPT") – examine scarcity conditions specifically. The pivotal supplier screen is based upon market conditions at the annual peak,[36] and because utilities typically plan to have reserves available during the annual peak, the pivotal supplier test would only coincidentally (and presumably rarely) be based upon scarcity conditions. The market share screen examines seasonal peaks,[37] which are even less likely to reflect scarcity conditions. Finally, the DPT looks at market conditions under off-peak, shoulder and peak conditions,[38] during which periods utilities should have sufficient reserves in place. Thus, as part of the required showing that demand resources "discipline bidding

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[36] Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697, 72 Fed. Reg. 39,904, 39,909 (July 20, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,252, P 35 (to be codified at 18 C.F.R. pt. 35), *clarified*, 72 Fed. Reg. 72,239 (Dec. 20 2007), 121 F.E.R.C. ¶ 61,260 (2007).

[37] *Id.* P 34.

[38] *Id.* P 95.

behavior to competitive levels during periods of operating reserve shortages," NOPR at P 119, the Commission must insist that RTOs' market power analysis go beyond the existing tests for measuring eligibility for market-based rates.

b) RTOs' market power analyses should measure whether demand response *successfully* mitigates market power

In addressing whether demand response resources mitigate market power, the Commission and RTOs should not rely on a simple recitation of advanced metering or other demand response penetration or participation rates without evidence that the amount of demand response *does* lower prices during times of scarcity. Demand response enrollment will not suffice if the demand does not respond during the time of need. As noted above, the 2007 FERC Staff Assessment of Demand Response and Advanced Metering (at 7) found load reductions in demand bidding programs of only 4-19%, even though enrollment levels were considerably higher. The Commission must require empirical evidence, such as critical loss analyses, that the amount of demand response during times of scarcity will effectively restrain prices.

Commissioner Wellinghoff recently highlighted the need to analyze demand response as part of an RTO's market power study in his dissent of the Commission's order on MISO's proposed ancillary services market.

> In this case, the higher likelihood of the exercise of market power in the ASM, coupled with approval of scarcity pricing, makes it particularly important for Midwest ISO to have a comprehensive approach in place at market start-up to respond to and, as necessary, mitigate inappropriate bidding behavior. Despite the importance of demand response to such a comprehensive approach, Midwest ISO's filing contains no factual record assessing whether demand response can effectively participate in its markets under its proposed rules. Without such a record indicating potential demand response to discipline bidding behavior,

> the reasonableness of Midwest ISO's overall proposal, and particularly its plans to implement scarcity pricing, is called into question.

Midwest Indep. Transmission Sys. Operator, Inc., 122 F.E.R.C. ¶ 61,172 (2008) (Commissioner Wellinghoff dissenting). The Commission should follow Commissioner Wellinghoff's lead and require that demand response be specifically analyzed.

c) RTOs' market power analyses should examine the incentive and ability to withhold demand response, especially by market participants with generation

The Commission must also examine the ability and incentive to withhold demand response resources in an effort to raise prices or create artificial uncertainty. The first and second of the four scarcity pricing approaches involve removing offer caps and allowing generation and/or demand response to set market clearing prices, while the fourth approach would allow the clearing price to be established based upon payments to emergency demand response resources. Under each approach, there may be opportunities for participating resources to try to raise the prices paid to them, especially if they have other resources, whether generation or demand response, in the market that would receive the market clearing price.[39] RTOs should thus assess whether the

[39] The general analytical framework described here is similar to the one the Commission has said that it will use in the merger context:

> The ability to withhold output depends on the amount of marginal capacity controlled by the merged firm, and the incentive to do so depends on the amount of infra-marginal capacity that could benefit from higher prices. For example, in a horizontal merger combining a company with significant baseload capacity with a company owning capacity on the margin under many season/load conditions, the theory of competitive harm would be that the combination of the "ability" assets with one company's existing "incentive" assets would increase the likelihood of the company exercising market power. Proper mitigation would address the harm to competition by reducing the merged firm's "ability" assets or its "incentive" assets through divestiture or some other method.

FPA Section 203 Supplemental Policy Statement, 72 Fed. Reg. 42,277, 42,286 (Aug. 2, 2007) [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,253, P 60 (2007), *order on clarification and reconsideration*, 122 F.E.R.C. ¶ 61,157 (2008).

ownership of generation and demand response resources, combined with the specific market rules for deploying them, provide the incentive and ability to exercise market power during times of scarcity.

d) RTOs should demonstrate that they have market mitigation measures that are effective under scarcity conditions

The Commission requires that RTOs have "provisions for mitigating market power and deterring gaming behavior, including, but not limited to, use of demand resources to discipline bidding behavior to competitive levels during periods of operating reserve shortages," NOPR at P 119, but RTOs should not be permitted rely on existing market mitigation measures without also showing that they are designed to address the specific market power concerns that arise under scarcity conditions. Part of this demonstration will require that the RTO assess market power risks under scarcity conditions, as described in Part I.E.2.a). above. Another part will need to address the fact that many RTO mitigation measures apply only to generation resources deemed to have significant effects on transmission constraints.[40] RTOs should show that all resources, whether generation or demand, that could affect prices under scarcity conditions are covered by mitigation measures.

e) RTOs must determine whether there is enough demand response available to respond under scarcity conditions, given reliance on demand response for capacity reserves and ancillary services

The Commission proposes that the demand response resources be permitted to participate in ancillary services market, NOPR at P 56, and the Commission has accepted ancillary services market proposals that allow demand response resource participation.

[40] *See* Southwest Power Pool, FERC Electric Tariff, Fifth Revised Volume No. 1, Attachment AF, Section 3.2; Midwest ISO, FERC Electric Tariff, Third Revised Volume No. 1, Module D, Section 63.4, *available*

See Midwest Indep. Transmission Sys. Operator, Inc., 122 F.E.R.C. ¶ 61,172, P 19. The Commission also recently accepted a Midwest ISO resource adequacy proposal that allows LSEs to satisfy resource adequacy requirements ("RAR") by relying on upon demand response resources. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,238, P 337 (2008). Given usage of demand response resources in non-emergency situations, for example, to provide operating reserves, the Commission should determine the degree to which demand response resources remain available to provide the demand response expected to discipline bidding behavior during operating reserve shortages. The Commission must protect against unquestioning reliance on demand response penetration rates and other measures without an examination of the market and conditions for which such resources are made available and the associated market rules.

f) RTOs must prepare statistics on experienced and expected frequency of scarcity conditions

The Commission should also examine statistics on the number of hours when scarcity conditions arose or are expected to arise. The scarcity conditions that trigger the NOPR's scarcity pricing proposals *should* arise only infrequently. *See* Kelly dissent[41] and Wellinghoff concurrence.[42] If a market, however, does not have sufficient resources to meet demand, it will face scarcity conditions more than infrequently, which would indicate that the RTO's policies with respect to resource adequacy are not effective. The Commission should not aggravate the potential consumer harm where scarcity conditions arise too frequently by relaxing market power mitigation. It should first fix the resource adequacy problem. As Commissioner Kelly noted, "[p]rior to implementing scarcity

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at http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-75b10a48324a?rev=86.

[41] NOPR at 73 Fed. Reg. 12,617, IV F.E.R.C. Stat. & Regs. ¶ 32,628 at 33,567.

pricing in any market, we must have resources in place to meet demand." *Id.* (Commissioner Kelly dissent).

3. The Commission Should Avoid Restrictive Scarcity Pricing Requirements that Preclude Beneficial Demand Response Approaches or Continue to Expose Consumers to Market Power Risks

The specific regulatory text proposed by the Commission states:

> Commission-approved ISOs and RTOs must modify their market rules to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.

Proposed 18 C.F.R. § 35.28(g)(1)(iv)(A). The Preamble expands upon this requirement:

> We propose to require each organized market to make a compliance filing, within six months of a final rule in this proceeding, proposing any necessary reforms to ensure that the market price for energy accurately reflects the value of such energy during periods of scarcity (i.e., an operating reserve shortage). Because there are regional differences in market design, we will not mandate any one type of reform in this area. Rather, each region may propose one of the four approaches described in the ANOPR (and summarized further below) or it may propose a different approach. Alternatively, a region may demonstrate that its existing market rules already reflect the value of energy during periods of scarcity and therefore do not need to be reformed.

NOPR at P 117. TAPS has an overarching concern with the Commission's reliance on "value-pricing" and more specific concerns that the regulation is too limiting.

The Supreme Court has rejected seller claims justifying higher prices for electricity based upon the value ascribed to the product by the buyer, noting that a "focus on the willingness or ability of the purchaser to pay for a service is the concern of the

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[42] NOPR at 73 Fed. Reg. 12,618, IV F.E.R.C. Stat. & Regs. ¶ 32,628 at 33,570.

monopolist, not of a governmental agency charged both with assuring the industry a fair return and with assuring the public reliable and efficient service, at a reasonable price." *Gainesville Utils. Dep't. v. Fla. Power Corp.*, 402 U.S. 515, 528 (1971). Electricity service is not a Picasso painting up for auction at Sotheby's. It remains essential to the nation's economy and the lives of its residents, which explains why the Supreme Court in *Atlantic Refining* emphasized the requirement for service "at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest." *See Atl. Ref. Co.*, 360 U.S. at 388. The Commission's value pricing policy, if adopted, could lead to unconscionable results: should an isolated village in the Allegheny Mountains of Pennsylvania go without electricity during an emergency simply because consumers there cannot outbid those in a Philadelphia Main Line suburb?

Furthermore, market forces may not always do a good job of assigning value to products such as reliable electricity. The 2007 *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy* of the Electric Energy Market Competition Task Force[43] (on which a Commission representative served and to which several other Commission staff contributed) stated (at 54 n.148):

> It is important to note that competition in wholesale electric markets may not lead to an efficient allocation of resources involving the services that prevent network collapse. Where there are "public good" aspects to the delivery of a good or service, such as with reliability, regulation may be the best way to ensure that the correct level of the good or service is provided. In some circumstances, however, market remedies may be available that are superior to regulation.

[43] *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, Interagency Electric Energy Market Competition Task Force (Apr. 6, 2007), *available at* http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf.

As the Task Force *Report* suggests, an approach where individual consumers are assigning value to electricity may actually lead to a misallocation of this essential resource.

In any event, before the Commission imposes the proposed scarcity compliance requirement, it should at least test its hypothesis that price caps are interfering with the proper valuation of energy products, thus deterring demand response. TAPS supports the proposal made by the National Rural Electric Cooperative Association ("NRECA") in response to the ANOPR that would remove "bid caps for demand response resources during emergency situations, provided that those higher bids for demand response do not set the market clearing price for all resources."[44] NRECA goes on to explain that this could elicit additional demand response during emergencies and "by differentiating between the price received by demand resources and generation resources, it would appropriately treat demand response in these out-of-market situations as an operational tool for preserving reliability rather than as a pure market participant." *Id.*

NRECA's proposal, if properly implemented, should not incent generators to create emergencies because they will not profit from them and, although adding to the uplift consumers must bear, will not exact the same degree of extreme hardship on consumers as elevating the market clearing price across wide swaths of the nation. Some TAPS members have instituted similar programs, compensating firm customers (as opposed to the interruptible customers that already receive a year-round demand charge credit for being interruptible under certain conditions) for reducing demand in severe

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[44] Comments of the National Rural Electric Cooperative Association at 16 (Sept. 14, 2007), *available at* eLibrary, Accession No. 20070914-5111.

emergencies. TAPS views this approach as having potential benefits in emergencies, with fewer adverse consequences than the proposals in the NOPR to relax mitigation.[45]

Perhaps more importantly from the Commission's "reform" perspective, the NRECA proposal would allow the Commission to obtain evidence regarding the prices demand resources require and whether price caps are, in fact, interfering with the market's producing those prices. If demand response resources are willing to participate at prices lower than the current offer caps, it will indicate that the offer caps are not the problem. On the other hand, if demand resources require higher prices than available in the market, the Commission can determine whether such participation can be achieved at lower cost through uplift or by allowing the demand resources to set the clearing prices (assuming protections against market power exercise are in place).

At a minimum, the Commission should allow RTOs to propose the NRECA approach as part of any scarcity pricing compliance requirement. TAPS is concerned, however, that the proposed regulation (18 C.F.R. § 35.28(g)(1)(iv)(A)), which requires rule changes "to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power," would preclude an RTO from proposing the NRECA approach. It might also preclude an RTO from

[45] However, care must be taken in designing and implementing NRECA's "operational" demand response programs to ensure that it does not work at cross purposes with other valuable LSE programs (e.g., for "planning" demand response). An LSE that has instituted programs that enable it to plan for elimination of certain loads during peak periods (e.g., by providing customers with a year-round demand charge credit) can avoid purchasing an expensive block of power, thereby providing savings to all the LSEs' customers. There is a danger that even the NRECA proposal could be implemented in a manner that would undercut such valuable programs. This potential highlights the need to involve LSEs (in nonretail access states, or municipals and cooperatives in retail access states that retain a traditional service obligation) in developing and implementing such programs (e.g., such LSE's load should participate through the LSE, who can take that participation into account in its planning process).

demonstrating that other demand response programs are beneficial. For example, Midwest ISO's recently approved Ancillary Service Market allows for participation of certain demand response resources[46] that do not set the market clearing price. This limitation was expressly recognized by the Commission in its order.[47] Such beneficial programs, which go along way towards advancing the Commission's goals, should not be foreclosed.

To ensure that the Commission's reform does not eliminate other beneficial demand response programs, TAPS proposes that the regulatory text be modified as follows:

> Commission-approved ISOs and RTOs must modify their market rules to allow (1) the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand or (2) payments to demand response resources. In either case, the rules must ~~so as to~~ maintain reliability while providing sufficient provision for mitigating market power.

In addition, the proposed definition of "operating reserve shortage" may be too broad for the intended purposes of permitting scarcity pricing only in "emergency" situations. *See, e.g.*, NOPR at P 123 ("Under the first approach, RTOs and ISOs would increase the energy supply offer caps and demand bid caps above the current levels only during an emergency."). As proposed, Section 35.28(b)(6) would read "An *operating reserve shortage* means a period when the amount of available supply falls short of demand plus the operating reserve requirement" (emphasis in original). But operating reserves are meant to be used, and such use in the ordinary course should not be deemed

[46] These are "Type 1 Demand Response Resources"—interruptible load that is either in an interrupted or non-interrupted state.

[47] *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 F.E.R.C. ¶ 61,172, P 188 (2008).

an operating reserve shortage triggering scarcity pricing, if operating reserves can readily be timely replenished. The definition should be refined to encompass only the (hopefully) rare shortage situation.

Besides its concerns about the overly restrictive regulatory text, TAPS has concerns that the NOPR's four approaches will increase consumer harm through market power exercise or force RTO development in directions not desired by stakeholders, despite the NOPR's statement that the Commission "will not mandate any one type of reform in this area" (NOPR at P 117). The Commission could take significant steps in addressing these concerns by requiring RTOs to undertake the market power analyses described in Part I.E.2. above and by modifying the regulatory text to make it more flexible. While TAPS recognizes that the Commission says RTO proposals must address market power concerns, until specific proposals are made, TAPS's concerns, as described below, remain.

The NOPR's first approach – raising energy bid caps and market-wide caps in an emergency (NOPR at P 123) – offers consumers no protection against market power exercise and thus would only produce unjust and unreasonable rates, absent meaningful market power mitigation. *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004), *cert. denied sub nom.*, *Coral Power, L.L.C. v. Cal. ex rel. Brown*, 127 S. Ct. 2972 (2007). If demand response is insufficient to restrain prices, the Commission would have to rely upon generators to limit their bids to non-exploitative levels. Generators, however, have neither the ability nor the incentive to determine a price that is just and reasonable under scarcity conditions. The generator would need to figure out what the efficient market price is and then bid at that level. Because electricity markets can change dramatically from hour to hour, this is a near impossibility.

Further, the generator is in no position to determine the value buyers place on keeping the lights on, assuming value pricing were permissible. The generator would thus lack sufficient information to accurately estimate the efficient market price. And even assuming the marginal generator could develop an accurate estimate, it has no incentive to do so where it has market power, which it almost always will have under scarcity conditions because of the absence of competing suppliers and of the very limited ability of load to reduce consumption. The price level that the generator finds most profitable may well be very different from the efficient price. Without the risk that load would decrease its demand substantially (enough to make the price increase unprofitable) in response to a high price and knowing that they must be called by the system operator to maintain reliable service in the load pocket, generators would have no incentive to "get the price right." Their only incentive would be to get the price high. Thus, this proposal is not consistent with the "Commission's core responsibility … to 'guard the consumer from exploitation by non-competitive electric power companies.'" ANOPR at P 5 (quoting *NAACP v. FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975)).

The second approach – raising bid caps only for demand bids (NOPR at P 124) – also suffers from a lack of proof that consumers can effectively express a value for electricity and, even assuming they can, that the Commission could lawfully allow prices to be set by the highest bidder, as would be the case for the sale of a masterpiece painting. While this approach might raise fewer market power concerns than the first, because generation offer caps would remain in place, that effect could be very limited if the market participant submitting a demand bid also had generation that could benefit from a price increase. *See* Part I.E.2.c) above. If the higher price yielded additional revenues that exceeded the added cost to load associated with the price increase, the proposal would do little to discourage artificially high load offers.[48]

The third approach – requiring RTOs/ISOs to rely upon demand curve pricing for operating reserves (NOPR at P 125) – risks mandating a particular type of reform, an RTO-run ancillary services markets. If regions, such as SPP, want to move towards Day-2 or Day 2½ markets, that effort should originate with stakeholders, not RTO management or regulators on First Street, NE in Washington, DC.

The fourth approach would set market-clearing prices at the payment made to participants in an emergency demand response program. NOPR at P 126. The Commission attempts to distinguish a "demand response bid" (4th approach) from a "demand bid" (2nd approach) by describing the "demand response bid" as "an offer by a purchaser to reduce its normal purchase by a given amount in return from compensation" and describing the "demand bid" as "an offer by a potential purchaser to buy a certain amount of energy at a given market price." NOPR at P 98 n.97. While the difference between the two approaches remains unclear, it may be that the fourth approach aims to set the clearing price at whatever payment the RTO makes to a demand response resource, such as air conditioning load, that reduces consumption during emergencies in return for a contractually established payment, perhaps determined by a regulatory body other than this Commission and outside the context of the RTO's market clearing

[48] The Commission's "ballot box" observation (NOPR at P 102) that this second approach received less support than the first approach proves only that the numerous generating interests preferred the first approach over the second. Given that the first approach would let them exercise market power, that preference is not surprising.

mechanism. In addition, TAPS remains concerned that if a market participant that can control whether such load is made available has other resources in the market, whether generation or demand, that would benefit from a higher clearing price, it could take actions to place a region into a scarcity condition artificially, simply to earn the extra revenues.

Regardless of the scarcity pricing approach approved for an RTO, the Commission should maintain some kind of safety-net. If the sky is the limit on scarcity prices and the Commission's experiment with scarcity pricing produces price spikes, such as occurred during the California meltdown or in the Midwest in 1997, the backlash will likely be significant, especially if the stratospheric price sets the clearing price across a broad region. One need only witness consumers current reaction to rising gasoline prices to grasp some of the potential fallout from unrestrained scarcity prices. More fundamentally, a "hands-off" approach is inconsistent with the Commission's consumer protection mandate. *Atl. Ref. Co.*, 360 U.S. at 388. The Commission should require RTOs to work with stakeholders in a region to develop a safety-net cap beyond which the prices will not be permitted to rise in the absence of adequate price restraining demand response.

Finally, if the Commission proposes nonetheless to relax or remove offer and bid caps, then it must revisit its approval of RTO/ISO markets that were justified on grounds that such caps prevented generators from earning revenues needed to recover investment costs. For example, a primary justification of ISO-NE's locational installed capacity market proposal, which eventually became the Forward Capacity Market, is that caps, such as $1,000/MWh, "take [] away" revenues needed for cost recovery. *See* Direct

Testimony of Steven E. Stoft, Exhibit No. ISO-17, *Devon Power LLC,* Docket No. ER03-563-030 at 6, 8 (Aug. 31, 2004).[49] If, due to the raising or lifting of mitigation caps, spot market prices can rise to the levels claimed needed to recover generator investment costs, a principal justification for organized capacity markets is eliminated, while at the same time consumers get hit with a double whammy – the high energy prices the capacity market was intended to replace plus the capacity market charges. In this regard, the Commission is incorrect when it states (NOPR at P 114):

> In regions that have already adopted forward capacity markets, the lifting of such price caps on energy would primarily *shift* revenues from capacity markets to energy markets. In New England and PJM, the revenues collected by generators in the energy market are *deducted* from the revenues that need to be recovered in the capacity markets.

The Commission's observation fails to account for the fact that only generators clearing the energy market that also happen to be clearing the capacity market will see the clawback of higher energy revenues caused by lifting price caps. Generators selling only in the energy market will keep the windfall. Prices in organized markets will not be the lowest possible reasonable rates if consumers are forced to pay for generation capacity twice, once via scarcity prices and again via capacity market purchases.

II. LONG-TERM POWER CONTRACTING IN ORGANIZED MARKETS

The NOPR (P 155) proposes to adopt one of the three proposals considered in the ANOPR[50] – requiring RTOs to dedicate a portion of their website for market participants

[49] *Available at* FERC eLibrary, Accession No. 20050620-0530.

[50] Among other things, it abandons the ANOPR's proposal (ANOPR at PP 93-94) to promote greater market transparency by requiring RTOs and ISOs to post information that could facilitate long-term contracts, such as by aggregating and posting information on long-term contract prices and quantities on a periodic basis.

to post offers to buy or sell power long-term. This proposal seems aimed at addressing the perception problem that the NOPR cites suppliers as asserting – that markets are operating well, but parties are unable to reach long-term contracts due to differing price expectations and differing assessments of the risk. NOPR at P 134.

While TAPS does not object to this proposal, we do not see it as addressing the more fundamental problems that are impeding long-term contracts and forcing TDUs to do everything they can to avoid the wholesale market, *e.g.,* by replacing the long-term purchased power contracts on which they have traditionally relied with direct investment in generation assets. As explained in TAPS ANOPR Comments (at 29-32), for an LSE with an obligation to serve, a long-term financial product priced on the basis of natural gas is no substitute for a long-term contract or investment in base load capacity (*e.g.*, coal). The operating costs of the unit matter – energy reflecting spot gas prices is not an economic way to serve base load needs. Also important (especially from a resource adequacy perspective) is the assurance that there is a physical unit backing up the supply matters – liquidated damages will not satisfy customers or utility boards that expect their supplier to have iron in the ground to ensure that the lights stay on. When LSE representatives express concerns about the absence of long-term contracts at prices that they find attractive, they are saying that they cannot find sellers of long-term products that have the physical and cost characteristics that they need to build a portfolio for economic, reliable and renewable power supply.

Part of the solution is ensuring that LSEs can secure transmission needed to economically deliver base load, and renewable capacity from its location often remote from LSEs loads.[51] TAPS is hopeful that the Long-Term Rights Final Rule would enable LSEs to secure long-term rights for new and existing power supply arrangements.[52] But that depends on follow through — the Commission insisting that RTOs follow through with planning and expanding the system to support the deliverability of existing and new long-term resources and the simultaneous feasibility of associated financial rights.

TAPS was therefore surprised and dismayed by recent orders that suggest the Commission is prepared to relieve RTOs of responsibility even to maintain the deliverability of long-term resources (apparently including those supported by network resource designations and long-term firm point-to-point reservations) to enable LSEs to count them for resource adequacy purposes. Instead, based on changes in system topology shown in its annual deliverability assessment, the RTO may be permitted to find such a resource no longer qualified to meet the LSE's reserve requirements and to subject the LSE to financial consequences for failing to plan for sufficient reserves.[53] Relieving RTOs of the obligation borne by every other OATT-governed transmission provider to plan and expand their system to support existing long-term firm transmission rights would put LSEs at risk of losing deliverability and associated resource adequacy value of their long-term resources (designated as network resources or supported by long-term firm point-to-point reservations). Such a policy is not a recipe to foster the long-term commitments that the NOPR correctly finds essential. *See* NOPR at P 134.

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[51] Peaking generation can often be sited locally.

[52] Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 71 Fed. Reg. 43,564 (Aug. 1, 2006), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,226 (to be codified at 18 C.F.R. pt. 42), *corrected*, 71 Fed. Reg. 46,078 (Aug. 11, 2006), *clarified*, Order No. 681-A, 71 Fed. Reg. 68,440 (Nov. 27, 2006), 117 F.E.R.C. ¶ 61,201 (2006).

[53] *See Midwest Indep. Transmission Sys. Operator, Inc*., 122 F.E.R.C. ¶ 61,283 at PP 278, 280.

If the Commission is serious about facilitating long-term contracts, it needs to do more than require RTOs to include a bulletin board on their website. At minimum, it must require RTOs to live up to the letter and spirit of its Long-Term Rights Rule, and prevent RTOs from making it risky for LSEs to rely on long-term contracts by vitiating the financial value of the resource, *e.g.*, by avoiding responsibility to maintain deliverability of long term resources so they can count for resource adequacy; by failing to plan to sustain the simultaneous feasibility of financial rights. As discussed in Part IV.D below, TAPS urges the Commission to measure RTO performance on this all-important effort and take steps to hold RTOs (and transmission owners) accountable, if they do not timely construct the transmission facilities needed to support these rights. It must also make sure that Order 890's joint, regional transmission planning process, which TAPS has strongly supported, is not window dressing.[54] The rest of the solution requires a better understanding of the problem.[55]

III. MARKET MONITORING POLICIES

A. Comments on MMU Independence

The NOPR sets forth a number of positive proposals to increase and ensure market monitoring unit ("MMU") independence. TAPS supports the proposal that each RTO or ISO include in its tariff (1) "a provision imposing upon itself the obligation to provide its MMU with access to market data, resources, and personnel sufficient to enable the MMU to carry out its functions," (2) "that the MMU shall have access to the

[54] Order 890's joint, regional transmission planning process leaves RTOs and TPs with decision-making authority (*see* Order 890-A at P 188), and does not ensure that plans reflect stakeholder input (*see* Order 890 at P 454) or that plans result in construction of facilities (*see* Order 890-A at P 178)

[55] As noted above, TAPS believes that American Public Power Association has raised serious issues about the operation and impact of RTO markets that merit Commission concern and attention.

RTO's or ISO's database of market information," and (3) "that any data created by the MMUs, including reconfiguring of the RTO/ISO data, be kept within the exclusive control of the MMU." NOPR at P 180. Especially if the MMU is not involved in day-to-day administration of the tariff, *see* NOPR at P 210, the Commission must require that the market monitor's resources be sufficient to allow it to understand RTO market operations as well as if the market monitor were administering mitigation.

TAPS disagrees, however, with the Commission's retreat from the ANOPR's proposal that ISOs and RTOs include a "provision directing the MMU to report to the Commission any concerns it has with inadequate access to market data, resources, or personnel, or to describe the steps it has taken with the RTO or ISO to resolve these concerns." NOPR at P 182. An obligation on the MMU to undertake such reports would empower the MMU, because it would remove the ability of the RTO to hold the MMU responsible for reporting to the Commission. While the Commission says that including such a requirement would suggest that the Commission anticipates non-compliance by RTOs, *id.*, that same reasoning would also suggest that the Commission should not include any number of tariff provisions, including the proposed requirement "specifying that [RTOs and ISOs] may not alter the reports generated by the MMUs nor dictate the conclusions reached by the MMUs." NOPR at P 199. Further, the actions of PJM management that led to the recent Commission order approving a settlement creating a new MMU structure for PJM underscores the need to impose compliance obligations, even on RTOs. *Allegheny Elec. Coop., Inc. v. PJM Interconnection, LLC,* 122 F.E.R.C. ¶ 61,257 (2008).

TAPS believes that the Commission can and should strengthen the independence of the market monitoring function and broaden its capabilities by requiring protection for RTO employees that suspect wrongdoing or believe the RTO is not fulfilling its responsibilities under the tariff. It should require RTO tariffs to offer whistleblower protections to RTO/ISO employees, especially those involved in mitigation administration, so that they can report suspicious conduct by market participants or deficient performance by the RTO to the market monitor or to the Commission without fear of retaliation from RTO management.

TAPS also disagrees with the Commission's declining "to propose a blanket requirement that all changes in MMU status, such as contract termination or renewal, be subject to Commission review and approval." NOPR at P 189. Such review would provide a backstop to ensure MMU independence and give market participants and the Commission a mechanism to assess whether the RTO has assigned FERC-required functions to the independent MMU and is funding the resources needed to carry out these responsibilities. Such review is no less important than the review of Commission-required ethics standards rules applicable to MMU employees, which the NOPR also proposes (P 213) and TAPS supports. While the Commission cites a "reluctance to impose a 'one size fits all' approach in structural areas," *id.* P 189, a procedural requirement to file the MMU contract or changes thereto with the Commission does not interfere with how the RTO structures its market monitoring function. The Commission has not provided a valid reason not to require the contract to be filed and reviewed.

B. Comments on MMU Structure and Functions

TAPS strongly supports the proposal that "the MMU, for purposes of supervision over its market monitoring function, should report to the RTO or ISO board rather than to management" and further that "management representatives on the board be excluded from this oversight function." NOPR at P 187. Strong, independent MMUs should be viewed as auditors, similar to what is required under Sarbanes-Oxley (and what should be standard among U.S. companies) whereby the board or a committee thereof selects the market monitor without management involvement. The board should have a permanent committee responsible for the market monitoring function that would interact with the market monitor, keep the board informed, and bring issues of concern to management's attention. Board members that serve on this committee should have backgrounds or expertise that permit them to interact effectively with the market monitor.[56] Board members should also receive training on how to ensure that their interactions with the market monitor do not compromise its independence.

In cases where an RTO has two market monitoring bodies, one internal and the other external, TAPS does not oppose the Commission's proposal to allow the internal MMU to "report to management with respect to both its market monitoring and administrative functions, and the external MMU report to the board," NOPR at P 187, so long as the Commission clarifies that the MMU functions set forth at P 189 and discussed below must be the *external MMU's* responsibility. This division of responsibility appears to be the Commission's intent, as seen in P 187 where the Commission says that "for purposes of supervision over its market monitoring functions, [the MMU] should report

[56] RTOs may need to recruit specifically for board members with the required background or expertise.

to the RTO or ISO board rather than management." TAPS is concerned that if the independent, external MMU (*i.e.*, the one that reports to the board) does not also have the NOPR-prescribed functions, however, the external MMU's role will be marginalized. For example, SPP has an External Market Advisor ("EMA") whose responsibilities have been cutback significantly during period that SPP has operated as a Commission-approved RTO.[57] Having a weak external market monitor report to the board, while allowing the internal MMU (that does all the work and has all the knowledge) report to management, will make the NOPR's direct-board reporting requirement a meaningless reform.

As for RTO functions, TAPS supports the ones identified in the NOPR at P 198 and set forth in the regulatory text at proposed Section 35.28(g)(3)(ii). TAPS urges the Commission to specify that the MMU's responsibility to "[r]eview and report on the performance of the wholesale markets" (*see* proposed 18 C.F.R. § 35.28(g)(3)(ii)(B)) includes examining whether RTO benefits are flowing to consumers. The market monitor can make this consumer-value assessment by examining, for example, whether in LMP markets investment in transmission, generation and demand response is occurring in areas with higher prices, which the Commission's LMP-based market design predicts should happen. If such investment is not occurring, the MMU should determine the impediments to the realization of such benefits. Another area the MMU should examine is whether FTRs are available for and being used to hedge the transmission/congestion costs experienced by LSEs. If FTRs are largely in the hands of entities whose interest is not in serving LSEs and their customers who ultimately bear the

[57] *See* Southwest Power Pool, Submission of Revision to External Market Monitoring Agreement, No. ER08-477 (Jan. 25, 2008) *available at* FERC eLibrary, Accession No. 20080129-0089.

cost of RTO-run markets and the congestion FTRs are intended to hedge, the MMU should make that known and the Commission should investigate.

Consistent with market monitor's independent role, it should not be an advocate for RTO rules or market design. Indeed, the Commission says that it does not "contemplate that the MMU make market design decisions itself, which are within the purview of the RTO or ISO through stakeholder processes and Commission approval." NOPR at P 195. While the RTO could seek the independent (*i.e.*, the one that reports to the board) market monitor's views on proposed rule changes or new market proposals, the independent market monitor should not submit testimony, as often occurs today, in support of an RTO market proposal. Otherwise, the market monitor risks becoming invested in the success of those proposals, which could affect its subsequent assessment of the RTO's markets. The Commission should, however, require the market monitor to be an intervenor in Commission proceedings on RTO market rule proposals so that the Commission has the benefit of the market monitor's independent views. Consistent with the NOPR's proposal that the market monitor advise the Commission and other interested parties on recommended rule changes, NOPR at P 198 and proposed 18 C.F.R. § 35.28(g)(3)(ii)(A), the market monitor's filing with the Commission should include any views the market monitor expressed to the RTO during the process of developing the proposed market rules.

The NOPR proposes "that MMUs be removed from tariff administration, including mitigation," but also "solicit[s] comments on the activities that would be needed to make the transition to RTO/ISO-administered mitigation, on any difficulties the MMU might be anticipated to experience in monitoring mitigation performed by the

RTO or ISO, and any additional sensitivities that commenters wish to raise regarding the proposal." NOPR at P 210. While TAPS does not oppose this proposal, it is concerned about the effect on the ability of the independent MMU to perform its responsibilities. Hands-on administration of mitigation provides market monitor staff with valuable information about how the market works. That knowledge can assist the market monitor to glean from often voluminous data whether certain bidding conduct suggests attempts to manipulate the market or exercise market power. To address these concerns, the Commission must require that the market monitor's resources be sufficient to allow it to understand RTO market operations as well as if the market monitor were administering mitigation. The Commission should also require frequent examinations (monthly, not just the NOPR-proposed (18 C.F.R. § 35.28(g)(3)(ii)(B)) quarterly) of market performance by the market monitor so that its staff does not need to ascend a steep learning curve each time it conducts an assessment.

C. Comments on Transparency and Information Availability

The Commission proposes that masked offer and bid data be posted on RTO/ISO websites with a lag of three months. NOPR at P 229. The proposal moves in the right direction from the prevailing 6-month standard, but the Commission can safely shorten the lag even further to a week (or less) and should do so.

There are successful models for making information, including bid-offer data, available on a real or close-to-real time basis. In other functioning, competitive electricity markets, market data is released routinely, and without the masking that FERC has required or approved to date. In the Australian National Electricity Market, for example, generating unit bid data is available on a next-day basis.[58] Likewise, the Balancing Mechanism Reporting System ("BMRS") website for the England and Wales market provides near real-time and historical data — including bid-offer data — on the National Grid Company's balancing of power flows in the electricity transmission system in England and Wales.[59] Data disclosures have not caused those markets to collapse.[60] On the contrary, competitive markets thrive on information, not secrecy. On the New York Stock Exchange, trade information is immediately available, and actions are traceable to those commanding the activity.[61]

Faster release of more information does not necessarily raise collusion concerns and may well help mitigate them. From antitrust law and economics, we know that concentration levels and ease of entry are leading factors affecting the ability of firms to collude. Other factors, such as information transparency, firm size, product homogeneity or heterogeneity, and prior evidence of coordinated activity, can play a role in specific cases, but are far from dispositive in all circumstances.[62] More information in the hands

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[58] This data is found at NEMMCO Market Management System (MMS) CSV Files, http://www.nemmco.com.au/data/csv.htm (last visited Sept. 14, 2007).

[59] On the BMRS website (http://www.bmreports.com), a wide range of data, including bid-offer data for each BM Unit, can be retrieved at http://www.bmreports.com/bwx_reporting.htm (last visited Sept. 14, 2007).

[60] *See, e.g.,* Comptroller and Auditor General, *The New Electricity Trading Arrangements in England and Wales* (2003), http://www.nao.org.uk/publications/nao_reports/02-03/0203624.pdf.

[61] In other contexts, such as securities regulation, transparency is favored because it breeds investor confidence, strengthens capital markets and leads to economic growth. *See* Claire Moore Dickerson, *Ozymandias as Community Project: Managerial/Corporate Social Responsibility and the Failure of Transparency*, 35 Conn. L. Rev. 1035, 1052 (2003) (citing Bernard S. Black, *The Legal and Institutional Preconditions for Strong Securities Markets*, 48 UCLA L. Rev. 781, 786-87, 835-38 (2001) and Joel Seligman, *The Historical Need for a Mandatory Corporate Disclosure System*, 9 J. Corp. L. 1 (1983)).

[62] *See* Margaret C. Levenstein & Valerie Y. Suslow, *What Determines Cartel Success?*, 44 J. Econ. Literature 43 (2006); *see also* U.S. Dep't of Justice & Fed. Trade Comm'n, *Horizontal Merger Guidelines*, §§ 2.11, 2.12 (1997); *In re High Fructose Corn Syrup Antitrust Litig.*, 295 F.3d 651 (7th Cir. 2002), *cert. denied*, 537 U.S. 1188 (2003); *Fed. Trade Comm'n v. Elders Grain, Inc.*, 868 F.2d 901 (7th Cir. 1989); *Hosp. Corp. of America v. Federal Trade Comm'n*, 807 F.2d 1381 (7th Cir. 1986), *cert denied*, 481 U.S. 1038 (1987).

of a larger number of competitors reduces the value of the information as a coordination tool, because there is a greater likelihood that individual competitors will use the information to compete harder and better. On the other hand, if only a few players with a sufficiently large share of the market have access to information, the risks of collusion increase. Moreover, transparency rules can be refined to keep confidential, or delay the release of, information that is the most sensitive and otherwise not available.

In fact, the current approach involving a significant time delay likely increases collusion risks. The greatest danger to LMP market design involves generators that derive market power from their control of multiple resources, because the intellectual foundation for the single-price auction model assumes that each offeror owns only one asset.[63] Large generation-portfolio holders know their offers for each of their multiple resources. Further, sources like Genscape already sell information on generator operating status. Consequently, those that would use such information to manipulate markets or for other improper purposes[64] can already obtain it, and a 3- or 6-month lag will not prevent them from doing so. Allowing RTOs to make it available for free and more quickly would have the salutary effect of enabling smaller market participants to compete on a level playing field, and enabling them and low-budget consumer representatives (*e.g.,*

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[63] *See* Robert C. McDiarmid, Lisa G. Dowden, & Daniel I. Davidson, *A Modest Proposal: Revoke the Nobel Prize? Recognize the Limitations of Theory? Or Grant a License to Steal?* 14 Elec. J. 11 (2001).

[64] Given the public availability of Genscape information and other means of acquiring information on a target plant's operating status, TAPS doubts there remains a homeland security basis for keeping such information non-public. If that case can be made, however, the proper response is to make the generator status information available to all industry stakeholders that demonstrate their bona fides as North American market participants. Critical Energy Infrastructure Information, Order No. 630-A, 68 Fed. Reg. 46,456, 46,457 (Aug. 6, 2003), [2001-2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,147, P 7 (to be codified at 18 C.F.R. pt. 388) ("[T]he Commission encourages these entities [RTOs and others] to provide information to legitimate requesters").

official state consumer advocates) to assist with market monitoring. The result should be more competitive markets than would otherwise be the case.

Further support for faster release of data may be found in the 2007 study, "Data Required for Market Oversight – A Concept Paper for the Electric Market Reform Initiative ('EMRI') of the American Public Power Association," which William H. Dunn Jr. of Sunset Point LLC prepared ("Dunn Study").[65] Mr. Dunn's study recommended that unmasked RTO electric market offer and bid data should be released on the day after the operating day, and the unmasked physical operating characteristics of generation resources should be publicly available. Dunn Study at 1. The study concluded that the benefits of faster release far exceed any additional collusion risks (at 14):

> The possible benefits to be obtained by the posting of resource and load-specific offer and bid data on the day following the operating day appear to far exceed the risks of additional collusion by those market participants inclined to collude. In fact, such data posting may help expose efforts to manipulate market prices and, as a result, discourage such behavior. Such rapid data posting also has the potential to create confidence in the markets and expose what goes on in the black box, thereby increasing the pressure on: (i) market participants to behave; (ii) RTOs/ISOs to efficiently and economically operate the markets; and (iii) market monitors to detect anomalous behavior on the part of market participants and/or RTOs/ISOs.

[65] http://www.appanet.org/files/PDFs/dunn2007.pdf.

TAPS supports the proposals that MMUs disseminate their reports to market participants, but finds unfounded the Commission's concern that including market participants in conference calls would be "unwieldy." NOPR at P 227. RTOs today successfully conduct stakeholder meetings via web and teleconferencing, and there is no reason why MMUs cannot utilize the existing RTO infrastructure for such phone calls. Another example of successful teleconferences involving numerous participants is NERC, which conducts board calls, sometimes with upwards of 100 participants. Most participants can be placed in listening mode, and a moderator can manage questions, if the meeting includes a Q&A segment. In the RTO context, questions might be limited to just a small portion of the call or to RTO staff or this Commission's staff, if it appeared that allowing everyone to ask questions would be unmanageable.

TAPS, however, opposes giving state commission staffs preferential treatment whether on conference calls or in the ability to make requests for information from the MMU, as proposed in the NOPR (PP 233-34). Market participants have as great a stake as state commissions in knowing whether RTO markets are performing well. They are also positioned to provide feedback to market monitors that could assist the market monitor in its responsibilities. Market monitors should have discretion, however, to deny requests for information that they deem to be overly burdensome or that distract the market monitor from other required tasks.

IV. RESPONSIVENESS OF RTOS AND ISOS TO STAKEHOLDERS AND CUSTOMERS

A. Need for a Consumer-Focused Mission Statement

TAPS pushed hard in its ANOPR Comments (at 6-11, 33-34) for the Commission to require RTOs to adopt a consumer-focused mission statement as a necessary predicate to making RTOs accountable to the consumers that depend on them for reliable service at an affordable price. In response, the NOPR (P 280):

> proposes to require that each RTO and ISO post on its web site a mission statement or charter for its organization. The Commission encourages each RTO and ISO to set forth in these documents the organization's purpose, guiding principles, and commitment to responsiveness to customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services.

While the NOPR would require the posting of "a mission statement," the contents is left to the RTO, with little or no Commission guidance. The NOPR merely "encourages" the RTO to include something about the "organization's purpose [and] guiding principles" (*id.*), but provides no direction on what that purpose and guiding principles should be. The NOPR similarly "encourages" but does not require the mission statement to contain some commitment to responsiveness to customers, other stakeholders, "and ultimately to the consumers who benefit from and pay for electricity services" (*id.*)*,* treating consumers as just another stakeholders class to which the RTO may choose to commit to being responsive.

The NOPR falls far short of what should be required of RTOs—Commission-approved entities entrusted to ensure that the FPA's goals are accomplished. Under the FPA, wholesale competition and well-oiled markets are not ends in themselves. Rather, the end is the one articulated in Section 205: just and reasonable rates. 16 U.S.C. § 824d. To do so, the Commission must "curb abusive activities by public utilities … and … protect consumers of electrical services from excessive rates."[66] As the Supreme

[66]*Fla. Power & Light Co. v. FERC*, 617 F.2d 809, 816 (D.C. Cir. 1980) (citations omitted). *See also FPC v. La. Power & Light Co.*, 406 U.S. 621, 631 (1972) ("The Natural Gas Act of 1938 granted FPC broad powers to protect consumers against exploitation at the hands of natural gas companies.") (internal quotation omitted); *Pub. Sys. v. FERC,* 606 F.2d 973, 979 n.27 (D.C. Cir. 1979) ("Both the Natural Gas Act

Court has explained, Congress intended jurisdictional sales "at the *lowest possible reasonable rate* consistent with the maintenance of adequate service in the public interest," and the Act was "framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges." *Atl. Ref. Co.*, 360 U.S. at 388 (emphasis added) (internal quotation omitted).[67] As recently reaffirmed by the Commission, "In Order No. 2000 … the Commission's goal was to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service… ."[68]

In contrast, the NOPR (P 5) generally recognizes that " [O]ur goal has been to identify any specific reforms that can be made to optimize the efficiency of organized markets for the benefit of customers, and ultimately the consumers who benefit from and pay for electricity services," and supports its scarcity pricing proposals on the assumption that demand response may "help reduce prices to all" (P 110; *see also* P 29) and "may be a low cost resource that can be used to meet operating reserve requirements at the lowest total cost of maintaining reliability" (P 111). It mentions Order 2000's goal of "ensur[ing] that electricity consumers pay the lowest price possible for reliable service"[69] only when reciting the (rejected) request of TAPS and others that RTOs be required to establish mission statements geared to that goal (P 268).

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and the Federal Power Act aim to protect consumers from exorbitant prices and unfair business practices.").

[67] While *Atlantic Refining* arose under the Natural Gas Act, courts have "repeatedly recognized the similarity of the two statutes and held that they should be interpreted consistently." *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[68] Promoting Transmission Investment through Pricing Reform, Order No. 679-A, 72 Fed. Reg. 1152, 1166 (Jan. 10, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,236, P 86 n.141, *clarified*, 119 F.E.R.C. ¶ 61,062 (2007).

[69] Order 679-A, P 86 n.141.

TAPS asks the Commission to move beyond the requirement for posting a mission statement which, at the RTO's election, include *some* purpose, principles, plus a generalized commitment to be responsive to all stakeholders and consumers. Instead, the final rule should require each RTO to file a mission statement that makes it *accountable* to consumers for meeting the Federal Power Act's purpose of ensuring that electricity consumers pay the lowest price possible for reliable service. Only a clear directive will be sufficient to reverse the current course, where TAPS members have heard RTO executives disclaim any obligation to have their actions guided by consideration of cost impact on consumers. It is apparent that RTO management views this Commission and state regulators as the only entities to which they are responsible and accountable.

The RTOs' mission must be clearly defined and specific, so that there is a standard to which the RTOs and their management can be held. The Commission will not fulfill its FPA obligation unless it clearly redefines the RTOs' mission to include provision of reliable service at the lowest possible reasonable rates, and requires RTOs to meet these goals. By establishing consumer value as a core goal of the RTOs, the Commission would focus the entire RTO organization on the achievement of this goal, aligning the RTOs' mission with the objectives of state regulators, federal policy makers, LSEs, and the consumers who ultimately bear the cost of the RTO's operations.

B. Criteria for Responsiveness Need to be Fine-Tuned to Achieve the FPA's Consumer-Focused Objectives

The NOPR requires RTOs to satisfy four criteria for responsiveness (Proposed Regulations, 18 C.F.R. § 35.28(g)(5)):

> (i) *Inclusiveness*. The practices and procedures must ensure that any customer or other stakeholder affected by the operation of the

> Commission-approved RTO or ISO, or its representative, is permitted to communicate its views to the RTO or ISO board;
>
> (ii) *Fairness in balancing diverse interests*. The practices and procedures must ensure that the interests of customers or other stakeholders are equitably considered and that deliberation and consideration of Commission-approved ISO and RTO issues are not dominated by any single stakeholder category;
>
> (iii) *Representation of minority positions*. The practices and procedures must ensure that, in instances where stakeholders are not in total agreement on a particular issue, minority positions are communicated to the board of directors at the same time as majority positions; and
>
> (iv) *Ongoing responsiveness*. The practices and procedures must provide for stakeholder input into RTO or ISO decisions as well as mechanisms to provide feedback to stakeholders to ensure that information exchange and communication continue over time.

TAPS certainly supports responsiveness, but is concerned that as expressed in the NOPR, the new criteria could be used to undermine, rather than further, the achievement of the FPA's consumer protection goal, and may reflect a step backwards from Order 2000's directives. Specifically, we would suggest that the second ("Balancing of Diverse Interests") criterion be replaced by:

> Due consideration of diverse interests, with actions consistent with FPA consumer protection obligations (*i.e.*, provision of reliable service at the lowest possible reasonable rates).

TAPS suggests this revised language out of concern that the "Balancing" criterion could too easily become an excuse for subverting the FPA's directives. As proposed, the RTO may not be satisfying the "Balancing" criterion if it gave greater weight to the views of those who asked it to perform its functions consistent with the Act's directives, than the views of those advocating policies that would increase their own profits at the expense of the consumers the Commission is entrusted to protect. Well-healed generator interests already out-number TDU interests in most working groups and the like. If an

RTO were simply to "balance" the well-represented and highly vocal views of generation interests with what is often the more sparsely represented views of TDUs and other consumer interests, the RTO would not be doing the job this Commission entrusted it to perform. The Act mandates provision of reliable service at the *lowest* possible reasonable rates, not at rates that gives equal voice to the desires of some market participants to maximize their revenues and the interests of LSEs seeking to provide reliable service at affordable rates.

While the RTO certainly should give due consideration to all viewpoints, its actions should be informed by the statutory requirements that will be used by the Commission to evaluate RTO filings. Order 2000's (at 30,993) expectation that the independent RTOs allow for lighter-handed regulation[70] cannot be fulfilled if the RTO's job is to simply balance interests, without duly weighting those interests in relation to the FPA's consumer-protection mandate and the consumer-focused mission the RTO is entrusted to perform.

TAPS is also concerned that the proposed "Balancing" criterion takes a step backward from Order 2000's governance principles. The NOPR describes this new criterion as making sure RTO deliberations are "not dominated by any single stakeholder category." NOPR at P 279. In contrast, Order 2000 required that no one class "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."[71] Order 2000's

[70] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809, 811 (Jan. 6, 2000), [1996–2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,089, 30,993 (to be codified at 18 C.F.R. pt. 35) ("Order 2000"), *order on reh'g*, Order No. 2000–A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,092, *appeal dismissed for want of standing sub nom*. *Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[71] Order 2000, 65 Fed. Reg. at 857, [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. at 31,074.

standard was recently adopted in Order 693 for Electric Reliability Organizations.[72] The "Balancing" criterion's "not dominated by any single stakeholder category" articulation thus invites greater deference to well-represented classes, to the detriment of those the FPA requires the Commission to protect.

TAPS urges the Commission not to water-down Order 2000's "no two/no one sector" standard, and not to transform independent RTOs, charged with carrying out their functions consistent with the Act's directives, into mere mediators between diverse stakeholder interests. To be clear, TAPS believes that all views merit due consideration (as the other responsiveness criteria would require). However, to preserve the RTO's ability to fulfill its consumer-focused mission, the "balance" bullet should be modified to require "Due consideration of diverse interests, with actions consistent with FPA consumer protection obligations (*i.e.*, provision of reliable service at the lowest possible reasonable rates)."

C. Achievement of Responsiveness through Hybrid Boards is Preferable to More Advisory Committees

On the question of how RTOs satisfy the new responsiveness criteria, the NOPR proposes a flexible approach – requiring each RTO to submit a compliance filing demonstrating that it has in place or will adopt practices and procedures to ensure that it is responsive to stakeholders and customers. While hybrid boards remain an option (so long as they have an independent majority), the NOPR views the board advisory committee alternative as "a particularly strong mechanism." P 277.

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[72] *See* Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, Order No. 672, 71 Fed. Reg. 8662, 8675-76 (Feb. 17, 2006), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,204, P 153 (to be codified at 18 C.F.R. pt. 39) (footnote omitted), *corrected*, 71 Fed. Reg. 11,505 (Mar. 8, 2006), *on reh'g*, Order No. 672-A, 71 Fed. Reg. 19,814 (Apr. 18, 2006), [2006-2007 Regs. Preambles] F.E.R.C. Stat. &

TAPS recognizes that some, including Commissioner Kelly in her partial dissent, have expressed concerns about hybrid boards. While we agree with Commissioner Kelly that a clear, consumer-focused mission statement (as advocated in Part IV.A above) could be helpful in driving towards RTO accountability, TAPS believes that with adequate protections, hybrid boards are a better means of achieving a responsive, accountable RTO than creation of more stakeholder advisory committees. As demonstrated in TAPS ANOPR Comments at 34-47, and the WPPI White Paper attached to those comments, appropriately structured hybrid boards have the greatest potential to efficiently and effectively refocus the RTO to be accountable and responsive to stakeholders, in a manner that can permeate the RTO's entire organization. By making stakeholders vested partners in decision-making, hybrid boards can change the existing dynamic, which all too often pits stakeholders against RTO, providing benefits less attainable by other means, *e.g.*, more stakeholder advisory committees. As summarized in TAPS ANOPR Comments at 42-43 (quoting WPPI's White Paper at 4-5):

- CEO or high level senior executives from the stakeholder community would enhance the quality and sophistication of the advice the board receives from stakeholders through the normal advisory process given their on-the-ground knowledge. The addition of a stakeholder perspective at the board level should lead to a more rich and thorough discussion of key policy issues.

- Given their level of decision-making authority, and thus freedom from second guessing within their own companies, CEO and high level senior executive representatives on the board are less likely to view their primary mission as holding the line on a predetermined corporate position, as often occurs in the existing advisory processes. High level senior executives are

Regs. ¶ 31,212.

more likely to seek creative solutions and help craft acceptable compromises when the board addresses delicate policy and financial matters.

- Stakeholder participation at the board level would allow those directly affected by the RTO's action to have a seat at the table when key cost issues are addressed. Given that RTOs/ISOs are not-for-profit entities that pass all costs directly through to their members, it should be no surprise that there is concern among stakeholders that the incentives to control costs are insufficient.

- Through board membership, CEOs and other board members representing the stakeholder community would obtain a full appreciation of what the RTO is attempting to accomplish and the challenges it faces. CEOs talk to one another. An explanation of why the RTO is undertaking particular initiatives may be better received by other RTO members if it is heard from interested board members, as well as management.

TAPS's suggestions for structuring hybrid boards should allay fears that RTO independence will be compromised and, as expressed by Commissioner Kelly (partial dissent[73]), that RTO boards "will suffer from a divisive atmosphere with suspicion as to whether non-independent board members were acting in the best interests of the RTO/ISO and its customers or the best interest of the particular market participant represented by that non-independent board member."

First, TAPS supports the NOPR's proposal (P 277 n.285) to limit stakeholder representatives to ensure they remain a minority and cannot overcome the vote of the disinterested board members. For the same reason, TAPS would also require independent directors to hold a majority on board committees.

[73]NOPR at 73 Fed. Reg. 12,618, IV F.E.R.C. Stat. & Regs. ¶ 32,628 at 33,569.

Second, TAPS would place additional restrictions on the manner in which the stakeholder board members are selected. As described in the WPPI White Paper (at 5):

> A key element of any successful hybrid board structure would be the quality of the stakeholder representation on the board. This element should be addressed in at least two ways: (1) stakeholder board candidates should be required to meet strict eligibility criteria like all other board members. Such criteria, at a minimum, should require CEO or high senior level executive, and (2) selection of the interested board members should require supermajority voting approval... .

Specifically, TAPS would limit stakeholder board members to persons viewed as deserving of the trust of stakeholders as a whole, rather than the narrow interests of a particular sector or the even narrower interests of a particular market participant. TAPS achieves that objective by requiring a cross-sector super-majority vote, as described by WPPI's White Paper (at 5):

> With respect to the selection process, the interested board members should not be elected only by their own sectors. Instead, an election of an interested board member should require an affirmative vote of 67% of all sectors. The supermajority voting requirement would help promote board membership of individuals widely acceptable to stakeholders and give the interested board members an incentive to broadly represent the stakeholder community.

The all-stakeholder super-majority vote requirement would go a long way to mitigate concerns that the stakeholder board members would use their position inappropriately to advance their parochial interests. Thus, in response to the NOPR's inquiry (P 278),[74]

[74] To address the NOPR's question at P 278 as applied to stakeholder advisory committees, no cross-sector super-majority vote would be necessary or appropriate for selection of sector representatives. Typically, the sector itself is free to determine the process for selecting the representative charged with representing its sector.

TAPS recommends requiring a supermajority of all eligible stakeholders for election of non-independent members of the board.[75]

Third, as a further check on stakeholder board members, hybrid board meetings should be required to be open (except for personnel, litigation, and other sensitive matters).[76] Open meetings would ensure that the stakeholder board members not only "talk the talk" as they are lining up the super-majority needed for their selection, but also "walk the walk" when participating in the board. A stakeholder board member who inappropriately steps out of line won't last long. More generally, opening up board meetings would enhance a board's sense of public responsibility and purpose. Because RTOs are not-for-profit entities, with public interest responsibilities, secrecy serves no legitimate purpose and contributes to board isolation and capture by management. While some RTOs are more open than in the past, others have a long way to go, continuing to meet primarily behind closed doors with open meetings as staged events.

Finally, as discussed in TAPS ANOPR Comments at 46-47, non-independent board members should cover a range of stakeholder views (which we suggest could be accomplished in five members[77]) and be restricted to senior executives. Restricting non-

[75] As noted in TAPS ANOPR Comments at 46 (and below), the non-independent directors should be kept to a manageable number that ensures a range of stakeholder views are presented.

[76] Confidential information (such as market monitoring information not appropriately shared with stakeholders) could also provided behind closed doors if necessary. As to the stakeholder board members, such information could be addressed through an appropriate confidentiality agreements or, if necessary, by recusal. Confidentiality issues should not be an obstacle to more generalized open meeting requirements or hybrid boards.

[77] TAPS suggested: (1) Generator (any type of generation owner, including IPPs); (2) Transmission owner with obligation to serve (includes stand-alone transmission companies); (3) End-use customers, either an industry management person with primary internal responsibility for energy decision making or the heads of ratepayer consumer advocacy groups; (4) Transmission-dependent, load-serving utilities (rotating between for profit and not for profit companies, unless they agree unanimously on a candidate); and (5) Others, covering stakeholders that do not fit into the above categories, including marketers, financial traders, and environmental representatives. TAPS ANOPR Comments at 46.

independent directors to senior executives would enhance their ability to take a broader view, as contrasted with the more partisan viewpoints voiced by the mid-level personnel that typically populate the RTO stakeholder process (and would inevitably populate any future advisory committee). This difference in perspective is reinforced by fact that unlike company-representation-focus of participants in the RTO stakeholder process or an advisory or "liaison" committee, stakeholder board members will owe a fiduciary duty to the RTO. TAPS members who have sat on hybrid boards report that they have cast votes that reflect the best interest of the organization even though the position was at odds with the more parochial view of their own system.

Thus, TAPS urges the Commission to make clear that it will allow properly structured hybrid boards (that meet the additional restrictions proposed by TAPS) as a means to meet new responsiveness criteria, while satisfying independence.

To the extent the RTO is permitted to and does rely on a board advisory committees (which is a less desirable option because, among other things, such committees lack the stature and decision-making authority to attract senior executives), TAPS asks that they be structured to the greatest extent to allow direct stakeholder access to the board, unfiltered by management, at the time the board is considering a particular issue. TAPS understands that SPP's combined Members Committee/Board meetings are more conducive to achieving this goal than the advisory committee structures in place in other RTOs. SPP Members of the Board and Members Committee meet together to discuss the issues, in an open meeting, where the Members Committee publicly votes first on issues (on an advisory basis), followed by the vote of the Board of Directors (by secret ballot). Further opportunity for direct stakeholder access (unfiltered by RTO staff) is provided through SPP committees that include both directors and stakeholders.[78] While TAPS continues to prefer hybrid boards, an SPP-styled advisory committee structure is more likely to yield benefits than other advisory committee structures (*e.g.*, that provide stakeholder input at a time that is poorly coordinated with Board consideration of a particular issue).

D. RTO Accountability

TAPS ANOPR Comments asked the Commission to mandate various measures to improve RTO accountability for costs it imposes on consumers within its region. Instead, the NOPR (P 281):

> encourage[s] each RTO and ISO to ensure that its management programs, including, but not limited to, incentive compensation plans for executive managers, give appropriate weight to stakeholder responsiveness. Such plans should give appropriate consideration to important service delivery goals such as reducing congestion costs, timely response to transmission service requests, prompt resolution of statements, billing, and disputes, and other customer service measures of performance.

The NOPR further notes that "RTO … executive management compensation plans may already be based on various measures of performance. If these already adequately take account of customer responsiveness, the RTO or ISO may report this in its compliance filing." P 281 n.286. Thus, the proposed "encouragement" may amount to nothing more than the status quo that the Commission acknowledges requires reform. *See* NOPR at PP 273-74.

More robust action is required if the Commission is serious about RTO reforms to achieve the responsiveness to stakeholders and customers that "plays an important role in

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[78] *E.g.*, Corporate Governance, Finance, Strategic Planning, and Human Resources Committees. SPP committee compositions can be viewed at http://www.spp.org/section.asp?pageID=2.

implementing the RTO and ISO policies and achieving its objectives in a manner that customers and other stakeholders perceive to be fair, balanced, and effective." NOPR at P 274. TAPS summarizes our specific responsiveness and accountability proposals, discussed in greater detail in our ANOPR Comments (most of which the NOPR does not address):

- Requiring independent, biennial study of all RTOs that benchmarks each RTO's operating costs, as well as the costs of particular RTO functions, against the costs of other RTOs and, where possible, against the costs of non-RTO transmission providers (*see* TAPS ANOPR Comments at 48).

- Requiring detailed, biennial, independent cost-benefit analyses (with results shown by state at delivery point levels) and RTO efficiency audits. These analyses should not be limited to production cost-savings, but instead measure achievement of the RTO mission–value via reduced consumer costs. Such value cannot be delivered unless (a) the RTO generates cost savings through efficiencies, and (b) those savings, or a very significant portion of them, are reflected in the delivered price of wholesale energy, or at least the prices charged load-serving entities (recognizing the state role in determining charges to end-users) (*see* TAPS ANOPR Comments at 48-49).

- Requiring RTOs to assess the cost/benefits of new initiatives or major rule changes *before* undertaking them, taking into account both RTO costs and costs to market participants, to track the actual costs and benefits of such implementation, and to be accountable for their projections (*see* TAPS ANOPR Comments at 49-50).

- Requiring annual public reporting of RTO performance measurements (with an opportunity for comment), as well as other mechanisms to hold RTOs accountable for performance measures, including: (1) success at relieving congestion costs (quantifying congestion costs and tracking the progress of congestion cost reduction efforts); (2) responses to interconnection and transmission requests (tracking associated backlogs and delays and the measures undertaken to eliminate them); (3) reliability and outage statistics; and (4) whether RTO transmission planning and expansion targets are met (including its obligations to plan and expand the transmission system to meet the reasonable needs of LSEs and to enable them to secure long-term rights for their long-term power supply arrangements) (*see* TAPS ANOPR Comments at 50-51).

- Requiring RTO senior management compensation to be tied to consumer-focused performance measures (*see* TAPS ANOPR Comments at 52-54):

- achievement of the RTO's consumer-cost lowering mission;
- independently-determined measures of customer satisfaction;
- reductions in congestion costs;
- RTO cost containment;
- reduction in interconnection and transmission queues;
- meeting aggressive planning and construction targets;
- strategic planning and internal analyses that reflect a consumer-focused mission; and
- other objective measures of high quality service.

- Requiring advance stakeholder committee review of each RTO's annual budget, with a specific allowance for stakeholder rejection or modification of the budget where a substantial majority of stakeholder sectors agrees. If the RTO board believes that a modified budget jeopardizes its ability to meet its obligations, the board should be permitted to appeal to the Commission. Such an appeal should occur with sufficient time and factual support to permit the Commission to resolve the issue, with meaningful consideration of the stakeholder rejection, *before* the budget takes effect (*see* TAPS ANOPR Comments at 54-55).

- The annual budget review process should include capital budgets reflecting the total expected costs of a major project, rather than just the current year's cost for a multi-year project, with the cost-benefit process and tracking discussed above (*see* TAPS ANOPR Comments at 54-55).

TAPS is particularly concerned about holding RTOs accountable for fulfilling obligations to plan and expand the transmission system to meet the reasonable needs of LSEs and to enable them to secure long-term rights for their long-term power supply arrangements, as Congress directed in Section 217(b)(4).[79] The NOPR seems to "check off" this task as accomplished by promulgation of the long-term rights rule.[80] But the

[79] 16 U.S.C. § 824q(b)(4), as added by Section 1233 of the Energy Policy Act 2005, Pub. L. No. 109-58, 119 Stat. 594, 957 (2005).

[80] *See* NOPR at P 22 ("The Commission has also acted to improve certainty in the cost of transmission for electric customers by creating rules for long-term transmission rights in Order Nos. 681 and 681-A.").

hard work is ahead. Creation and maintenance of needed long-term rights, through expansion of the transmission grid to support those rights, is not self-effectuating. As TAPS Chairman Roy Thilly described at the February 27, 2007 Technical Conference in this proceeding, where an RTO determines long-term rights based upon a simultaneous feasibility test, the grid must be built to maintain the simultaneous feasibility of long-term rights for both existing and new resources in order for these rights to fulfill the goals of FPA Section 217(b)(4).[81] RTOs must be held accountable for timely constructing transmission to support needed long-term rights.

This problem is illustrated by MISO's Long-Term Transmission Rights ("LTTR") proposal and associated orders.[82] Although the Commission directs MISO to strengthen the link between long-term rights and transmission planning and expansion,[83] it is *LSEs* that will end up holding the bag if either MISO or MISO Transmission Owners fail to construct upgrades needed to maintain the feasibility of existing long-term rights.[84] With respect to long-term rights for LSEs' *new* long-term baseload resources, MISO is not required "to provide advance guarantees of LTTRs before the [new] generation facilities go into service."[85] Transmission customers are expected to finance and make huge generation and transmission investments with no assurance that they will receive long-term rights needed to make reasonably-priced deliveries to serve their own loads.

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[81] 16 U.S.C. § 824q(b)(4).

[82] *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 F.E.R.C. ¶ 61,143, *order on rehearing*, 121 F.E.R.C. ¶ 61,063 (2007).

[83] 119 F.E.R.C. ¶ 61,143 at P 193.

[84] If long-term rights within MISO become infeasible during their term, LSEs no longer have the right to automatically convert them into FTRs (*id.* P 55); and the Order suggests that the term of already-allocated long-term rights could be curtailed by subsequent Commission decisions (*id.* P 149).

[85] 119 F.E.R.C. ¶ 61,143 at P 155. *See also order on rehearing*, 121 F.E.R.C. ¶ 61,063 at PP 29-30.

Accountability questions are similarly raised by a recent order suggesting that the Commission may be willing to absolve MISO of responsibility to maintain deliverability of designated network resources required for LSEs to count them for resource adequacy purposes.[86]

Because LSEs that have no control over the RTO's transmission planning and construction may well bear the risk of an RTO's failure to perform this critical function, the Commission should adopt performance measures that track construction of transmission needed for existing and new long-term rights and to otherwise maintain deliverability of designated resources. These measures should be used to hold RTOs and Transmission Owners — the entities in the best position to control and manage the risks of that process — accountable, by requiring them to share the burden of failing to plan and build necessary transmission upgrades.

Finally, TAPS asks that the Commission recognize the need for RTO accountability not only for the operation of their markets but also to reevaluate whether they are serving the intended purposes and to recommend modifications. TAPS members in several RTOs have noticed that financial players seem to be garnering a disproportionate amount of the value from FTR markets, resulting in a huge flow of dollars to Wall Street, and away from LSEs that support the grid and from consumers who bear the congestion charges FTRs were designed to hedge. While PJM has recently filed a complaint pertaining to potential market manipulation by such interests,[87] no RTO

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[86] *Midwest Indep. Transmission Sys. Operator, Inc*., 122 F.E.R.C. ¶ 61,283, PP 278, 280 (2008).

[87] *See* Complaint of PJM Interconnection, LLC against Accord Energy LLC, Docket No. EL08-44 at 29 (Mar. 7, 2008).

has refocused on the fundamental question of whether the FTR markets are serving their intended congestion-hedge purpose and how they should be restructured to do so.

CONCLUSION

TAPS requests that in developing the final rule, the Commission modify the NOPR to take account of these comments.

Respectfully submitted,

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