

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Long Term Transmission Rights in
Markets Operated by Regional
Transmission Organizations and
Independent System Operators

Docket No. AD05-7-000

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

The Transmission Access Policy Study Group (“TAPS”) appreciates the opportunity to comment on the time-critical issue of long-term transmission rights in markets with locational pricing. We urge the Commission to seize the opportunity to adapt its short-term-focused LMP markets to accommodate investment in fuel-diverse, baseload generation and spur much-needed investment in transmission. Many TAPS members are ready and willing to make investments in new clean coal and renewable generation that will enhance our nation’s fuel diversity and energy independence, while reducing market clearing prices borne by consumers. However, the absence in today’s RTO markets of long-term rights to support delivery to load of such resources at a predictable price undermines the ability of TAPS members and other load serving entities (“LSEs”) to make and finance such investments, or enter into the long-term power purchase commitments that IPPs require to support their financing. The high installed cost of baseload coal generation cannot be justified if, because of the inability to obtain a long-term right from source to loads, the LSE is likely to pay gas-based LMPs for the energy produced as a result of congestion.

The unavailability of long-term transmission rights is something new. As might be expected from an industry characterized by highly capital intensive, long-lived assets, the long-term transmission rights needed to support such investments have been the norm, and were a key ingredient of the Order 888 regimen. However, they somehow got lost in the shuffle when new LMP markets, which are focused on maximizing short term efficiency, were created.

Today's RTO markets may fit the business model adopted by those suppliers in retail access states that have no interest in long-term supplies. However, this short-term focus does not meet the needs of load serving entities with an obligation, whether by contract (*e.g.*, joint action agencies with 35-year contracts with their member municipals) or under state law, to provide reliable service at stable prices. If RTO markets cannot be adapted to also accommodate the needs of such LSEs—the only ones capable of supporting the next generation of baseload coal or nuclear resources¹—consumers who stand to broadly benefit from such investments will be severely short-changed, and the Commission will have abdicated its mandate to ensure just and reasonable wholesale rates.

¹ See testimony of Mike Morris, President, Chairman and CEO of American Electric Power during the May 13, 2005 technical conference held in Charleston, West Virginia, in *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources*, Docket No. AD05-3-000 (“Coal Transmission Technical Conference”) regarding the difficulties of financing new baseload units in Ohio, a retail competition state (Tr. at 230):

We've asked the Public Utility Commission of Ohio to step out of the box and find under the provider of last resort authority, the opportunity to approve a regulated rate of return power plant going forward. First off, in today's world, I don't think you can raise the capital for a billion dollar merchant plant. I think the capital investors, working off of a bad model of natural gas being \$2 a million Btu's as far as the eye can see, went into a real heavy storm, and I don't think you'd see them repeat that performance. I don't think you'll see a major megawatt breakthrough clean coal and/or new nuclear built into a jurisdiction that does provide for that kind of regulatory treatment. That is just, I think, the reality that we all face.

If RTO markets are to fulfill their promise of delivering low cost energy to consumers, long-term rights for the generation that can produce such energy must be brought back into the mix. Any short-run efficiencies produced by LMP markets will be worth less and less if such markets continue to have the unintended side-effect of discouraging needed long-run investments in baseload generation and transmission. If RTO markets with locational pricing are just an expensive means to deliver high cost energy from resources that can be installed close to load and to allocate increasingly scarce, natural monopoly transmission resources to those prepared to pay the most, then the Commission's pro-competitive, pro-consumer intent will have been lost.

TAPS suggests pragmatic approaches to bring Commission policy back into a balance, where the short-term efficiencies claimed by LMP markets can be achieved without sacrificing our ability to invest in new baseload and renewable resources, while preserving the value of existing investments in accordance with the Commission's April 28, 2003 *Wholesale Power Market Platform White Paper* ("White Paper").² We propose several alternative forms of new long-term rights that should be made available for the limited set of new resources where they are needed the most—baseload and renewable resources that cannot be located close to load and therefore cannot otherwise be protected from congestion risk. We propose rights of ten-year duration, with a rolling right to renew,³ which would enable LSEs to achieve delivery cost certainty over the 40-year life of a generating plant without requiring an up-front commitment for the full

² Filed in Docket No. RM01-12-000, available at <http://elibrary.ferc.gov>, accession no. 20030429-3008; see also http://www.fer.gov/industries/electric/indus-act/smd/white_paper.pdf (last viewed June 27, 2005).

³ E.g., at the end of year one, the LSE will have to give notice that it wishes to retain the right in year eleven, or take its chances in the normal annual allocation process after the tenth year.

period, with all the attendant risks. The ten-year rolling term also enables the transmission right to fit into a realistic RTO transmission planning and expansion process, which we believe to be crucial to assuring both the financial integrity of the rights and the construction of transmission required to support them as well as robust competition. Because the long-term right is intended to hedge congestion from specified generation to load, the right is best structured as a right more limited than a conventional FTR. Thus, we propose “Dispatch-Contingent FTRs” that are tailored to achieve their limited purpose, without creating opportunities for windfalls or excessive risk for the holder, although we also suggest alternative structures (FTR/ARR obligations; and priority to annual allocation with assured availability).

In short, TAPS points the way for the Commission to accommodate the needs of load serving entities, and thereby support investment in the new baseload and renewable resources required for fuel diversity, to maximize energy independence, and to provide consumers the benefits of adequate supplies of energy at stable prices, while allowing those with other business models to retain their short-term focus.

I. INTEREST OF TAPS AND COMMUNICATIONS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.⁴ As entities entirely or predominantly dependent on transmission facilities owned and controlled by

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

others, TAPS members have supported the Commission's initiative to form truly independent regional transmission organizations to foster efficient investment in transmission and generation facilities, and to provide for non-discriminatory transmission access. As load serving entities, TAPS members participating in RTOs with LMP markets have a strong interest in making those markets support the generation and purchased power commitments required to meet out legal obligations to serve our wholesale and retail customers at the lowest reasonable cost over the long-term.

Communications regarding these proceedings should be directed to:

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

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

II. THE PRESSING NEED FOR LONG-TERM RIGHTS

As LSEs, TAPS members have a statutory or contractual obligation to serve our wholesale and retail customers at the lowest reasonable cost over the long-term, consistent with reliable service and good environmental stewardship. This paramount objective requires us to obtain and maintain a cost-effective power supply portfolio over the long-term. We accomplish this objective with a diversified mix of resources, with transmission service commitments matched to the duration of the associated resource commitment.

The overwhelming majority of the energy that we supply to our customers is produced from the resources in our portfolios, particularly baseload and intermediate resources. On a daily basis, if economic, we substitute spot market energy for energy that we would otherwise obtain from our own resources. While this optimization function is valuable, spot market energy purchases represent a very small percentage of total energy provided to our customers.

As we construct our power supply portfolios, we make long-term commitments to generation resources based upon a delivered price expectation. Putting aside capital costs, this expectation is driven by a delivery component and a commodity component. Under the Order 888 tariff, the delivery component risk was our load ratio share of the increase in the embedded cost revenue requirement of the transmission system as system upgrades were made plus a load ratio share of cost-based redispatch required to maintain firm transactions (after interrupting non-firm uses). This risk was quite predictable and not significant financially. The commodity component, driven by our fuel choice and the accuracy of our estimate of future fuel prices, was our primary delivered price risk.

Order 888 provided the transmission pricing certainty needed to support the financing, and protect the economic value, of high capital cost investment in baseload resources. Under the OATT, when we designated a new network resource, we generally requested transmission service for the term of our resource commitment. Our request was subject to a source-to-sink (generator-to-load) deliverability test. If we passed, firm transmission service was granted. If not, a study identified needed system upgrades and firm service was granted subject to the completion of the upgrades.

As a condition of obtaining this long-term firm service, we made a long-term commitment to pay our load ratio share of the embedded cost of the provider's transmission system, including upgrades necessary to maintain all firm service granted by the provider, for the full term of our service commitment. This commitment provided the transmission owner with valuable long-term financial and planning certainty. In exchange, the transmission provider agreed to plan and expand its system to assure that the firm transmission service from our network resources was comparable to the service provided to its own native load customers.

Order 888's long-term firm transmission service provided us with a virtually perfect hedge against congestion costs. We could count on the transmission provider to deliver the output of our network resources to our load at no additional cost for virtually all hours of the year. If significant congestion developed that required the transmission provider to curtail use of the transmission system, all non-firm transactions were shed before firm network and point-to-point service. All parties' network resources were subject to redispatch on a least-cost basis to maintain firm service, and the increased cost was to be shared among network users, including the transmission provider's native load. (Curtailements or TLRs of firm service were extremely rare.) If a transmission provider failed to fulfill its tariff obligation to plan for our needs on a basis comparable to the needs of native load, the provider's native load shared the pain.

Thus, under Order 888, once firm transmission was granted, the delivery price was essentially locked-in. The Order 888 regime afforded us the certainty needed to sign long-term power purchase agreements and to finance and construct new high capital cost baseload generation dedicated to our loads.

All this has changed with the introduction of LMP markets. Network resource designation, now judged on aggregate deliverability⁵ (instead of source-to-sink deliverability basis), assures no delivered-price certainty. Instead, LSEs are subject to volatile congestion charges reflecting the difference between the price at the location of the generation as compared to the price at the load. The only way to achieve delivered-price certainty roughly comparable to that enjoyed under Order 888 is through an FTR, which pays (or charges) the holder for this locational price difference. To maintain the financial integrity of the FTR system, however, the availability of FTRs has generally been limited to those simultaneously feasible. LSEs are annually at risk that the rights they need to hedge congestion on existing or new resources will be pro rated. As the Staff Paper confirms, no RTO offers new long-term rights for new resources.⁶

Thus, in RTO markets with LMP, not only is the value of our existing generation investments that were predicated on the Order 888 regime at risk, but new baseload investments become highly risky. Specifically, we face the untenable risk that we will incur the high capital costs of baseload generation investment, only to receive (due to congestion) delivered energy costs at our load that reflect gas-fired generation costs.

⁵ As described further in Part IV, the new aggregate deliverability test does not require LSEs to demonstrate that a new network resource can be delivered to the LSE's specific load on a firm basis. Instead, the RTO requires only a showing that the output of the resource is deliverable to the RTO's "aggregate" energy pool without overloading the transmission system. If so, the resource will be granted "network resource" status. Once a resource is granted status as a network resource under the aggregate deliverability test, any LSE in the RTO's footprint may designate the resource as its own network resource even if it would not pass a source-to-sink deliverability test.

⁶ RTOs do offer new long-term rights for participant funded upgrades. In Order 2003, for example, the Commission noted that PJM's generator interconnection protocol provided that customers who participant fund Network Upgrades would receive transmission rights that are "well-defined, long-term and tradeable." *Standardization of Generator Interconnection Agreements and Procedures*, 104 F.E.R.C. ¶ 61,103, P 700 (2003) ("Order 2003"), *order on rehearing*, 106 F.E.R.C. ¶ 61,220 (2004), *order on rehearing and directing compliance*, 109 F.E.R.C. ¶ 61,287 (2004).

For example, a 600 MW coal unit costs roughly \$1 billion to construct, while 600 MW of gas-fired peaking capacity costs only about \$300 million. At today's coal prices, the variable production cost from a baseload coal plant would be less than \$20 per MWh. In comparison, variable production cost from a gas-fired peaking plant would be about \$80 per MWh. In the Order 888 world, if we paid the coal plant's high capital costs, we'd be assured delivery of the \$20 per MWh coal-fired energy produced (assuming the plant achieved network resource designation). In contrast, under locational pricing, we could spend \$1 billion on coal-fired capacity and still face the risk that, due to congestion between the location of the baseload resource and our load, our delivered energy price will reflect the \$80 per MWh production cost of gas-fired capacity.⁷

We do not need to spend an extra \$700 million to be subject to paying for \$80 energy. To incur the high fixed cost of baseload coal-fired generation and end up with a gas-fired energy price at the load due to congestion would be a disaster for customers. But this is exactly the risk that the Commission is forcing LSEs to take by failing to require RTOs to provide long-term congestion protection

Financial rating agencies recognize this risk. In a report prepared in September 2004, Moody's indicated:

[T]here is potential risk in the short-term marginal pricing model being used in various regional energy markets in the U.S. Without long-term contracts for transmission rights and price certainty for the transmission of energy from new generation facilities, cost recovery in the long term may not

⁷ We recognize that the specific congestion charges will depend on the LMP at the generator, as well as the load. For example, in hours when those LMPs separate, if the LMP at the load reflects the \$80 per MWh production cost of gas-fired capacity and the LMP at the coal plant remains close to \$20 per MWh, then the difference would be \$60 per MWh. Even if that does not occur in every hour, we would face the real and difficult-to-quantify risk that we could be required to pay large, unhedged congestion charges over the life of the unit.

be assured. The certainty of cost recovery represents a major factor in the credit assessment of financings for new generation projects.⁸

According to *Megawatt Daily*, in May 2005, Moody's commented that "use of locational marginal pricing by [RTOs], which may eliminate long-term transmission contractual agreements, could impair certainty of transmission access to recover debt financing costs for new generation projects."⁹ These real world difficulties make it much more risky to invest in the resources needed to serve our customers economically over the long-term and to secure a healthy energy future for our nation.

The Commission cannot treat the absence of long-term rights needed to spur generation and transmission investment as a transitional problem in less mature markets. The assumption that spot market pricing will bring about needed investment in generation and transmission has been repeatedly debunked by rating agency reports,¹⁰ testimony at Commission technical conferences,¹¹ and experience. While LMP market short-term

⁸ "Credit Issues Resurface as New Electric Generation Projects by Public Power Utilities Take Center Stage," Moody's Investor Service, September 2004, at 4.

⁹ Public Power Facing Cost Problems: Moody's, *Megawatt Daily*, May 6, 2005, at 9.

¹⁰ 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.

¹¹ See, e.g., Technical Conference, *Transmission Independence and Investment*, Docket No. AD05-5-000 and PL03-1-000 (Apr. 22, 2005) ("Transmission Investment Technical Conference"), Tr. at 37-38 (Larson, Trimaran Capital Partners):

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

price signals may not do a bad job of inducing installation of gas peakers and even some gas combined-cycle plants, its track record on baseload coal units that would lower LMPs and costs to consumers is grim.¹² It is no mere coincidence that virtually ALL new plants planned for construction in MAAC are gas,¹³ even though eastern coal is nearby. Investments with significant capital costs relative to operating costs (*e.g.*, coal), are not so easily accommodated without long-term FTR support, especially given the frequent need to site such facilities remote from load.

The current model is not working even in the most mature LMP markets. PJM's Board has concluded that reliability in the Eastern section of the PJM Region may be compromised as early as 2008, and that "PJM would be imprudent to rely on energy

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.

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 February 4, 2004 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: "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. at 153 (Baliff, CSFB). In the words of one investment banker: "I think the economists like volatility, but the marketplayers don't." Tr. at 262 (Newman, Warburg Pincus).

¹² Similarly, to finance wind generation, long-term contracts are typically required, but obstacles are created by the unavailability of "long term firm transmission service needed to attract financing." *See* Notice, Agenda and Staff Paper for the December 1, 2004 Technical Conference on Wind Energy, *Assessing the State of Wind Energy in Wholesale Electricity Markets*, Docket No. AD04-13 (November 22, 2004) at 23 and 25.

¹³ *See* MAAC Response to the 2004 NERC Data Request (EIA-411) (August 2, 2004), *available at* http://www.maac-rc.org/reports/eia_ferc_nerc/downloads/2004maac411.pdf (last visited June 24, 2005), at 46.

market scarcity prices” to ensure that needed generation gets built.¹⁴ According to the Board, PJM’s experience has shown that market signals from short term markets simply will not encourage the investment needed to address long-term generation capacity needs. *Id.* Short term markets have not encouraged the construction of needed transmission, either. According to Audrey Zibelman, PJM’s Executive Vice President, at the April 22, 2005 Transmission Investment Technical Conference, PJM has been “very, very disappointed” by the results of its planning process for “economic” transmission expansion. Tr. at 72. PJM identified long-term rights as part of the solution to moving from a “minimalist transmission policy” that has produced “transmission system on life support as opposed to that robust system we want.” *Id.* at 73, 138.

PJM is not alone in urging a new approach. Earlier this month, Chairman Wood appeared before Congress to urge action to improve transmission “as the nation moves to develop new clean-coal and nuclear generation facilities.”¹⁵ In May 2005, the Commission hosted a technical conference to “explore possible changes that would better accommodate, in particular, the increased participation of coal-fired energy in wholesale markets.”¹⁶

¹⁴ Letter from Philip G. Harris to PJM Members and Stakeholders regarding Reliability Pricing Model (“RPM”) at 4 (March 22, 2005), available at <http://www.pjm.com/committees/members/downloads/ltr-to-mc-stakeholders-replaces-311560.pdf>; Attachment A available at <http://www.pjm.com/committees/members/downloads/attachment-a-to-3-22-mc-stakeholders-letter.pdf>; Attachment B available at <http://www.pjm.com/committees/members/downloads/attachment-b-to-bom-ltr-to-stakeholders.pdf> (last viewed June 27, 2005).

¹⁵ Press Release, “FERC Chairman Urges Congressional Action to Improve Transmission, the ‘Weakest Link’ in U.S. Power Supply System” (June 8, 2005).

¹⁶ Press Release, “Regional Planning, Coal-Fired Resources Explored at FERC Conference in West Virginia,” *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-fired Resources*, Docket No. AD05-3-000 (May 13, 2005).

This issue cannot be put off. Many TAPS members are at one stage or another in considering participation in new baseload or renewable facilities. The Commission's failure to provide a mechanism where we can be assured of obtaining the long-term FTRs needed to support the commitment to and financing of these investments affects our choices today. These choices will have lasting effects, not only on TAPS members' generation portfolios, but on generation choices made throughout organized markets and thus the delivered cost of energy to consumers for decades. Absent prompt creation of a clear path to the long-term delivered price stability TAPS members were previously able to achieve through the Order 888 OATT, baseload generation will lose out in the competition with peakers located near load. If load must pay high gas-driven LMPs anyway, why not take the cheap installed-cost way out, instead of paying for high-installed cost baseload coal generation that promises broad consumer benefits by lowering LMPs? Wind alternatives will similarly suffer. This is not good policy. Nor is the absence of long-term rights in LMP markets consistent with the Commission's stated intent that customers in restructured wholesale markets would have the option of obtaining service "comparable to ... existing firm transmission service" under the Order 888 OATT,¹⁷ and Order 888, which requires deviations from the *pro forma* OATT be "consistent with, or superior to" the OATT.¹⁸

¹⁷ *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,451 (Aug. 29, 2002), FERC Stat. & Regs. ¶ 32,563, P 145 (2002).

¹⁸ *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,539, *reprinted in* [1991-1996 Regs. Preambles] FERC Stat. & Regs. ¶ 31,036, at 31,770 *clarified*, 76 F.E.R.C. ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), *reprinted in* [1996-2000 Regs. Preambles] FERC. Stat. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 F.E.R.C. ¶ 61,248 (1997), *aff'd in part and remanded in part sub*

The Commission must get RTOs quickly on track to assuring long-term rights consistent with the public interest in providing consumers access to energy at the lowest reasonable cost. As RTOs substitute financial for physical rights, the paramount objective must remain the same—*i.e.*, long-term rights first and foremost must provide long-term certainty that the economic value of baseload generation investments is protected and can be delivered to customers. We strongly urge the Commission to develop and make available a long-term right that supports investment in new baseload resources equivalent to the protection historically afforded to these critical generation resources, and to make such rights available as well to renewable resources. These objectives must be accomplished if RTO markets with locational pricing are to provide value to customers over the long-term.

III. LONG-TERM RIGHTS THAT WORK WITH LMP MARKETS

TAPS recognizes that incorporating long-term rights into today's LMP markets and RTO planning processes poses challenges. For that reason, TAPS has sought to structure its proposals in the narrowest form that can achieve the intended result. We suggest tailored approaches designed to achieve long-term congestion hedges only in the limited circumstances where they are most needed, with a term that accommodates the RTO planning process. TAPS' solutions should not only support generation investment, but should also spur a more effective and accountable RTO transmission planning and expansion process. Thus, we provide a direction that should broadly benefit markets and the consumers the Commission is statutorily commanded to protect.

nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998).

In Section A below, we address the treatment of existing resources. Section B presents the general characteristics of the new long-term rights TAPS proposes for new resource commitments: (1) eligibility limited to selected new baseload and renewable resources; and (2) rolling ten-year terms for long-term rights. In Section C, we outline three alternative design solutions for new long-term transmission rights that meet crucial LSE needs while working within the framework of RTO markets with locational pricing.

A. Long-Term Rights for Existing Resource Commitments

While these comments focus on new long-term rights for new resource commitments, the Commission cannot ignore existing generation commitments. As LSEs entrusted with ongoing obligations under state law and contracts with member municipalities to provide reliable electric service at affordable, predictable delivered prices, we have spent years, and billions of dollars, assembling power supply portfolios. As transmission dependent utilities (“TDUs”), we have had to fight hard for the long-term firm transmission rights that support the commitment to and financing of those investments, many of which have years to run.¹⁹ Because many TAPS members were forced to look remotely for power sources that would put us in competition with our host utility, we are particularly vulnerable to congestion risk if the existing transmission rights on which those resource decisions were predicated are undermined.²⁰

¹⁹ See, e.g., Supplemental Protest Submitted on Behalf of Wisconsin Public Power Inc. at 20-33, in *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER04-691-000 (filed May 7, 2004), which documents TAPS member WPPI’s efforts over a 20-year period to secure reliable firm transmission rights for its resources.

²⁰ In contrast, a large vertically-integrated utility typically relies on generation on its own transmission system, and therefore closer to its load.

While FTR allocations for existing resources should continue to be handled by individual RTOs on a region-specific basis, all regions should be required to satisfy the Commission's commitment, in its April 28, 2003 "Wholesale Market Platform" White Paper, that existing customers would be held harmless, and would retain their pre-existing transmission rights and rights for future load growth.²¹ NYISO and PJM, where historical resources receive full protection through mechanisms other than long-term FTRs, appear to meet this requirement.²² MISO provides less complete protection of existing rights and appears poised to discard even those protections after only five years—a result inconsistent with the White Paper principles—and should be directed to modify its treatment of existing rights to assure those rights are not reduced or eliminated.

B. New Long-Term Rights for New Resource Commitments – Eligibility and Term

All RTOs should be required to offer new long-term transmission rights for new resources, and those new rights must be carefully crafted to work in conjunction with RTO markets over the long haul to properly shape generation and transmission investment decisions. To move this effort promptly ahead, the Commission should

²¹ See, e.g., April 28 White Paper at 5, 10 ("these rights [FTR rights that protect against congestion costs] would be allocated according to existing contracts and existing service arrangements in order to hold customers harmless"); Appendix A at 7-9 ("We will ensure not only that existing customers retain their existing rights, but also that they have the ability to obtain rights for future load growth") and n.8 ("Existing rights to service will be preserved. If necessary to meet these requirements, the RTO or ISO will create counterflow FTRs to make the aggregate set of FTRs physically feasible. If this results in a revenue shortfall, it could be recovered through an uplift charge."), see n.2, above.

²² Staff Paper at 10, n.11. See also PJM Open Access Transmission Tariff, Section 7.4.2 at Second Revised Sheet No. 408 Superseding First Revised Sheet No. 408, available at <http://www.pjm.com/documents/agreements.html> (last accessed June 27, 2005); New York Independent System Operator, Inc., Open Access Transmission Tariff, Section 2.2 at Original Sheet No. 63, available at http://www.nyiso.org/public/webdocs/documents/tariffs/oatt/body_oatt.pdf (last accessed June 27, 2005).

provide specific guidance on how those rights should be structured. TAPS recommends that new long-term FTRs have the following general characteristics: (1) eligibility limited to selected new baseload and renewable resources; and (2) rolling ten-year terms.

1. Long-Term Rights Should be Limited to Selected New Baseload and Renewable Resources

While TAPS members would prefer that new long-term rights be more broadly available, we have narrowly limited our proposal to those new resources commitments where it is needed the most. TAPS proposes that such rights be made available to hedge congestion price risk for long-lived, capital-intensive units that by their nature often cannot be sited close to load. New nuclear units plainly will not be built at load centers. As described at the Coal Transmission Technical Conference,²³ new coal baseload resources must be sited near rail, water, and high voltage transmission, and must take account of air quality attainment areas, local political acceptance, potential citizen opposition, and a variety of other factors that severely limit where units can be located. Renewable resources also have siting restrictions. They typically can be located only at the source of the fuel.²⁴ These resources will by necessity often be located remote from load, with inherent congestion risk for which there currently is no way of hedging over the long-term.

²³ See, e.g., Tr. at 49 (Jeff Wright, Director of the Infrastructure Division of the Office of Economic Projects); Tr. at 195-200 (Jacob Williams, Peabody).

²⁴ See Notice, Agenda and Staff Paper for the December 1, 2004 Technical Conference on Wind Energy, *Assessing the State of Wind Energy in Wholesale Electricity Markets*, Docket No. AD04-13 (November 22, 2004) at 12-13 ([M]any of the best resource areas are located far from load centers.... While fossil fuel-fired counterparts locate near load centers to avoid transmission constraints, wind resources must be sited where the wind blows. Nationally, strong wind sites are located an average distance of 500 miles from major metropolitan centers....”).

These new coal, nuclear, and renewable resources should therefore be eligible for long-term rights. In regions where new baseload resources will be gas-fired, application of long-term rights to those units may be appropriate—especially where, as in New England, the zonal-for-load/nodal-for-generator LMP treatment can result in congestion charges even for generation built at the load.²⁵

In view of their intended purpose—providing LSEs a hedge against congestion costs associated with delivery to load of the output of a new generator, thus promoting such investments—the rights should be defined as real source (or border, if the source is located outside the RTO) to real sink. They are not intended to provide a long-term bonanza or congestion-free pathway to a trading hub.

Whether the right can be supported financially by the existing grid or requires upgrades,²⁶ the amount of the long-term right should be defined by the amount of the LSE's MWs of commitment (by direct investment or power purchase) to the eligible new resource.²⁷ Unlike the long-term rights now associated with participant funding, they should not be tied to the capacity created by associated transmission upgrades, if any.²⁸

²⁵ Most RTOs with LMP pricing use nodal prices for both load and generation, so that if a generator were located at the load, congestion risk should be minimal because the LMPs should be the same or very close. In ISO-NE, however, LSEs cannot eliminate congestion risk by placing generation at the load; because ISO-NE uses zonal LMPs for load and nodal LMPs for generation, the LMPs may be quite different even for generation located at the load. Further, to participate in a baseload gas generation, TDUs may have no choice except to participate in generation remote from some, if not all, of its dispersed loads.

²⁶ As discussed in Part V, cost responsibility for upgrades would depend on the applicable transmission pricing methodology.

²⁷ As discussion in Part C(2), depending on how the long-term right is structured, a right in an amount less than the full MW commitment may be appropriate for those renewable resources with low capacity factors.

²⁸ Making the amount of the long-term right depend on incremental transfer capacity created by an upgrade not only would be insufficient to support the intended purpose of promoting generation investment, but it would discourage efficient location decisions. For example, assume an LSE was proposing to make a 300 MW participation commitment in a generator at a location with sufficient capacity for delivery without congestion of 250 MW of output, but which required an upgrade to create the additional 50 MW of transfer capability required. Under a participant funding approach, it would be entitled to only a 50 MW long-term

Finally, consistent with the proposed rolling 10-year term of the long-term rights (discussed below) and the intent to tie the rights into the planning process, these rights should be limited to those entities making at least a ten-year commitment both to the new resource and to pay the transmission system costs.

By narrowly limiting eligibility for such rights to those instances where it is most critical, TAPS seeks to facilitate integration of these rights into RTO markets. By restricting eligibility for these rights and integrating them with transmission planning, this approach should address concerns about the liquidity of short term FTR markets and leave room for those market participants with a short-term business model. As discussed below, the operating characteristics of the resources eligible for such rights interact with the nature of the rights proposed to facilitate solutions that are workable both for LSEs and the RTOs, and which minimize the opportunity for gaming.

2. Long-Term Rights Should Have a Rolling Ten-Year Term that Affords the LSE Unconditional Renewal Rights

Under Order 888, LSEs were able to obtain, through the network resource designation process, transmission rights that spanned the life of the resource commitment in exchange for a long-term commitment to take service from the transmission provider. In the RTO context, long-term rights for eligible new resources could be structured to reproduce key elements of this bargain. To balance the LSEs' continued need for long-term delivered-price certainty with the concerns expressed in the Staff Paper regarding the risks associated with long-term rights in the LMP context, TAPS proposes long-term

FTR for the new capacity created, which is hardly sufficient to support a 300 MW investment. Only generators choosing really bad locations could obtain long-term rights in amounts close to the capacity of the new generation.

rights with a rolling ten-year term. That is, an LSE that enters into a long-term commitment with a qualifying resource would receive a 10-year right with a ten-year transmission rolling renewal right. The LSE would be required to notify the transmission provider in year one if it wanted the FTR in year 11; in year two, it would notify the transmission provider if it wanted the FTR in year 12, etc. If the renewal right is not exercised in any given year, the long-term right would expire ten years later, and the LSE would have to take its chances in the normal annual FTR allocation process. LSEs that seek to cancel early could be subject to an appropriate cancellation fee.

A ten-year term with an assured right to renew on a rolling basis would meet the needs of LSEs seeking to finance the generation, *e.g.*, over a 30-year term, so long as the renewal right was unilateral to the LSE, unconditional, and not subject to any additional charges. The LSE could demonstrate to the investment community that it had a right to a congestion hedge for the full 30-year term of the financing, with no added renewal charge (*e.g.*, based on the cost of upgrades required to maintain those rights), so long as it timely exercised its renewal rights. This structure mitigates concerns with the risks of committing to very long-term rights in markets whose structure is still evolving.

The proposed rolling ten-year term, with advance renewal rights, also mitigates the risk to the RTOs, by tying the initial right and the renewal rights to a realistic RTO transmission planning process,²⁹ and pairing them with a long-term payment commitment on the part of the LSE. A transmission right structured in this way would give RTOs the

²⁹ A ten-year planning horizon seems appropriate for this purpose; and at least one RTO, PJM, has announced plans to develop a ten-year planning process to replace its existing five-year system. Letter from Philip G. Harris to PJM Members and Interested Stakeholders at 1 (May 31, 2005) (Attachment A to this pleading). RTOs with shorter planning horizons would still be required to accommodate rolling 10-year rights, but would address those rights through multiple shorter-range plans.

advance notice necessary to integrate long-term transactions and long-term transmission rights into their regional planning process. The ability to count on long-term commitments should allow RTOs to justify construction of transmission upgrades, if necessary to support the long-term rights over the life of the commitment.³⁰

C. Specific Designs for Workable New Long-Term Rights for New Resource Commitments

TAPS offers the following rough sketch of possible alternative structures that could be used to craft solutions that address congestion price risk for LSEs, while promoting sensible network upgrades and minimizing unintended side-effects on short-term RTO markets. Our preference is for limited, FTR-like rights that have value only to hedge congestion from the eligible baseload or renewable resource when it runs.³¹ This type of Dispatch-Contingent FTR would provide a hedge very similar to the firm transmission that was provided under the Order 888 OATT (although only for a subset of network resources), and it is narrowly tailored to avoid creating opportunities for windfalls or excessive risk for the rights holder.

In the alternative, it should be possible to craft a solution based on conventionally-designed, long-term FTR/ARR obligations, or by implementing an

³⁰ A similar approach has been used in the gas transportation context. Pipelines have been able to support construction of new transportation capacity based on long-term contracts—typically ten or fifteen years long—from customers willing to commit to the pipeline’s transportation service. Although there are important differences between gas pipelines and electric networks, the basic planning principle is the same: where transmission customers are willing to make long-term commitments to transmission service, transmission providers should be able to plan and build upgrades to the transmission network to support that service.

³¹ The Staff Paper identifies long-term physical rights and FTR options as possibilities in RTO markets. Staff Paper at 12-13, 17-19. TAPS would support those approaches, as they provide rights equivalent to the firm transmission rights that they had in the Order 888 regime. However, the Commission may be reluctant to mandate physical rights or long-term FTR options in RTOs that have implemented LMP pricing in day ahead and real time markets. As discussed below, if over TAPS’ objection, the upgrades initially required to support the long-term rights are to be participant funded, the long-term rights granted

FTR/ARR allocation protocol that gives priority (with meaningful assurance of full allocation) to long-term right holders in annual FTR/ARR allocation processes. While either of these alternatives could theoretically be designed to provide many of the same benefits as Dispatch-Contingent FTRs, they pose additional problems.

1. Dispatch-Contingent FTRs that Hedge Congestion from the Identified Resource Only When it Runs

Order 888's long-term firm transmission service provided LSEs with a virtually perfect hedge against congestion costs. In contrast, conventional FTRs produce a continuous stream of revenues or charges based on the difference in LMPs at the source and sink, even when the resource associated with the FTR is idle. The resulting mismatch exposes long-term right holders to additional risk and creates large potential windfall benefits in the form of FTR revenues.

This problem would be eliminated by offering new long-term rights that produce revenues or impose charges only when the identified plant runs. If the plant is operating, the value/cost of the Dispatch-Contingent FTR would be the difference between the LMPs at the source and sink; if the plant is not operating, the value/cost of the such FTR would be zero. A long-term, Dispatch-Contingent FTR would more accurately hedge congestion for the associated resource. This is true for all types of resources, although the difference is more dramatic for renewable resources with low capacity-factors and/or performance that varies from year to year. Dispatch-Contingent FTRs would provide a congestion hedge similar to the one provided by Order 888, which was adequate to support the financing of high capital cost investment in baseload resources.

for the transfer capacity created should be FTR options.

In theory, long-term rights configured in this manner could encourage dispatch of units that would otherwise be uneconomical.³² This theoretical issue should not be a problem in practice, however, for the limited resources TAPS proposes to make eligible to receive long-term rights. Baseload coal and nuclear units, for example, will run virtually all of the time; their marginal costs are typically very low, so there should be relatively few hours when it would be uneconomical to run them. For renewable resources such as wind, run-of-the-river hydro, and geothermal, LSEs have virtually no dispatch control.³³ Plant owners and operators do not have the power to decide—for economic reasons or any other motivation—when nature will decide to send wind or water in their direction.

Dispatch-Contingent FTRs would also eliminate the creditworthiness problem that the Staff Paper identified as a concern for conventional FTRs. Staff Paper at 9. For long-term right holders, creditworthiness issues may arise if congestion reverses and FTR charges are incurred in hours when the right holder is not engaging in a transaction between the source and sink associated with the FTR. TAPS' proposal addresses that problem in two ways. First, long-term rights would be limited to specified baseload and renewable resources, and those rights would be defined as real source to real sink. Second, by restricting FTR payments and charges to hours when the identified resource is

³² It was due to concern about such inefficiencies that the Commission restricted the availability of MISO "Option B" to grandfathered agreements that settled. *Midwest Independent Transmission System Operator, Inc.*, 108 F.E.R.C. ¶ 61,236, PP 264-70 (2004), *Order on Rehearings and Compliance Filings*, Midwest ISO Energy Markets, 111 F.E.R.C. ¶ 61,042 (2005), *appeal pending*. Thus, while MISO Option B shares attributes with the more limited rights described above, our proposal does not suffer from the hazards some argued were associated with Option B.

³³ Although hydro facilities with storage capacity typically provide some level of dispatch control, they also share key characteristics with the other types of generators for which long-term rights are appropriate—*i.e.*, very limited siting discretion and high capital costs.

actually running, Dispatch-Contingent FTRs would essentially eliminate exposure to unhedged FTR charges when congestion reverses. If LMPs are higher at the generator than at the load, the LSE holding the Dispatch-Contingent FTR would only incur an FTR charge for the difference in LMPs during hours when its generator is producing energy and the LSE can offset that FTR charge with LMP payments that the generator would receive for such energy.³⁴ When the eligible generator does not run, the LSE would be relieved of any FTR payment obligation.

By the same token, an LSE who holds a Dispatch-Contingent FTR would not receive any FTR payment if LMPs at its load are higher than at the generator, but the LSE's generator does not run. It would therefore have no incentive to acquire the FTR for its value as an FTR, separate and apart from its role as a hedge against congestion between a specific generator and the load to which it is dedicated. Particularly in the context of a renewable resource with a low capacity factor, this restriction would limit the amount the RTO would need to pay out for a Dispatch-Contingent FTR as compared with a conventional FTR obligation.

RTO markets should be able to accommodate long-term, Dispatch-Contingent FTRs without significantly disrupting the operation of short-term markets. The eligibility criteria will restrict the pool of resources for which LSEs may seek long-term rights; and the real-source-to-real-sink requirement and minimum 10-year term commitment may deter some LSEs who otherwise would be eligible for such rights. Moreover, because

³⁴ Absent the Dispatch-Contingent FTR, the LSE could pocket the profit from the higher LMP at the generator when congestion reverses.

they eliminate windfall payments to FTR holders, Dispatch-Contingent FTRs should have very limited appeal for market participants interested in FTR speculation.

The more tailored approach of Dispatch-Contingent FTRs comports with TAPS members' limited aims. As should be clear, we are seeking to hedge generation delivery costs, not to make out like bandits on FTR speculation. Thus, we believe this more limited right, which will hedge congestion while respecting the basic structure of RTO markets with locational pricing, is the best solution.

2. Long-Term FTRs/ARRs

If FERC rejects TAPS' recommended approach, there may be alternative ways to craft a workable solution. One option would be to model long-term FTRs along the lines of today's annual FTRs, but with a longer term. Specifically, they could be designed as a long-term (rolling 10-year) FTR obligation.

The long-term rights could also be configured as long-term (rolling 10-year) ARR.³⁵ Long-term ARRs could be structured to entitle the holder to revenues from successive auctions of shorter-term (*e.g.*, annual) FTRs. In theory, this approach could provide an effective hedge for LSEs who make long-term commitments to eligible new resources, while promoting greater liquidity in short-term FTR markets and more flexibility for the RTO to configure short-term FTRs.

However, if long-term transmission rights are issued in the form of ARRs, ARR holders must have the right to convert those rights directly to FTRs without participating in an auction process. Rights to automatic conversion, which are consistent with the

³⁵ Such ARRs must be configured on a source-to-sink basis, not on an aggregate load basis as in ISO-New England.

practice in PJM, are essential to allow ARR holders to avoid risk of inaccurate valuation by bidders, as well as the transaction costs of participating in an auction that the ARR holder supposedly can always win by submitting an excessive bid that it will not ever be called upon to pay.³⁶

In contrast to Dispatch-Contingent FTRs, long-term right holders could face both significant risks (when congestion reverses and the identified resource is not running, *e.g.*, when it is on maintenance) and windfall benefits. For high capacity-factor resources like baseload coal and nuclear plants or certain renewable resources (*e.g.*, geothermal or hydro plants during certain seasons), the additional risk might be manageable. Because those units are planned to run almost all of the time, the hours when the plant is running and the hours when the FTR would generate charges or credits should closely match.

For certain renewable resources, however, there is likely to be a large mismatch. Many renewable resources are intermittent (*e.g.*, wind generators and run-of-the-river hydro plants), and their owners have little or no control over when they run. For these types of units, a conventional FTR obligation equal to the full amount of the LSE's commitment to the resource would significantly over-pay or over-charge the LSE over the life of the resource commitment.

In theory, a conventional FTR could be designed for each such generator that has the same expected value as congestion between the generator and the LSE's load. For example, a 50 MW wind generator with a capacity factor of 40% might be eligible for

³⁶ In the absence of automatic conversion rights, an ARR holder could also face creditworthiness concerns if forced to "bid to the max" to ensure that it wins the FTRs associated with its long-term ARR. In addition, while the ARR holder would theoretically recover the full amount of any payment it makes in such an auction, the specific design and implementation of the FTR auctions must be carefully monitored to ensure that each ARR holder that "bids the max" is always made whole.

25 MWs of long-term FTRs from the source to sink, if the 25 MW FTR would provide revenue equal to the expected value of congestion. Determining the appropriate long-term FTR quantity, however, would require very complex calculations and projections for each unit eligible for a long-term right, both in terms of projected dispatch and projected congestion charges. Since generation from some units may vary dramatically from year-to-year (*e.g.*, run-of-the-river hydro plants during droughts), that variation must also be taken into account in the FTR calculation.

While TAPS would prefer the more narrowly tailored long-term Dispatch-Contingent FTRs, long-term FTRs/ARRs should be workable, albeit with added risk as well as complex implementation protocols to assure that the appropriate rights are available for allocation to each eligible baseload or renewable resource.

3. Assured Priority for Long-Term Right Holders in Allocation Processes for Short-Term Rights

Both PJM and NYISO have developed approaches that provide full protection for historical resources without necessarily allocating conventional long-term FTRs. In both RTOs, holders of existing long-term rights receive priority in the FTR allocation process, either by allowing them first crack at the available FTRs each year before the allocation process begins, or by reserving the transmission capacity necessary to honor those rights, so that it is not included in the normal FTR allocation process.

A similar process could be used to allocate rights to LSEs that make long-term commitments to eligible new resources. Instead of a long-term FTR, shorter term FTRs could be offered to such LSEs each year, before the normal FTR allocation process begins. Each LSE would be entitled to designate FTRs from the eligible resource to the LSE's load, up to the full amount of its commitment to the resource (or, in the case of

low capacity factor renewable resources, some other quantity calculated to reflect the expected value of congestion between the generator and the load). This approach would give LSEs greater flexibility than long-term FTRs, since LSEs could decide on an annual basis whether they wanted the FTR associated with their source and sink. Having that option would obviously be attractive for LSEs, because it would allow them to mitigate the risks and implementation problems associated with long-term conventional FTRs. However, it may make it harder for the RTO to plan for simultaneously feasible FTRs over time if LSEs can opt out on a yearly basis.

The priority right to an annual allocation process would be meaningless if insufficient FTRs are available. The long-term congestion pricing hedge required to support baseload generation investment will not be achieved if the LSE's FTR rights are subject to availability, and thus pro rationing, on an annual basis. To avoid being a hollow promise, or simply displacing existing rights, there must be assurance that the RTO would construct to achieve and maintain simultaneous feasibility of these FTRs, in combination with FTRs for existing resources consistent with the White Paper, or be accountable for a failure to do so (*i.e.*, by identifying and uplifting the congestion costs of fully supporting long-term FTRs, as discussed in Part VI below).

IV. REGIONAL TRANSMISSION PLANNING AND EXPANSION THAT SUPPORTS LONG-TERM RIGHTS AND COMPETITIVE WHOLESALE MARKETS

An integral part of development of long-term transmission rights is the adoption of a planning and expansion process that creates a robust grid sufficient to support such rights. Although a key purpose of RTOs was to improve transmission planning and

expansion process to achieve a robust regional grid,³⁷ the opposite has occurred. As highlighted at the May 13 Coal Transmission Technical Conference, transmission investment has fallen behind; investment in new transmission investment lines is needed to avoid increased reliability problems, avoid increasing already high congestion costs, and enable growing loads to be served from new baseload coal generation consistent with environmental limitations.³⁸

Despite the clear need for transmission expansion to address these problems, as well as to minimize opportunities for the exercise market power and the need for intrusive regulation, we are caught in cycle where little gets built while we dissect the purposes for upgrades and determine beneficiaries for projects that necessarily have broad benefits. As noted above, even PJM has conceded that the current regimen, with its sharp distinction between (rolled-in) reliability and (participant funded) economic upgrades, is producing “disappointing results.”³⁹

Do we want a “minimalist” transmission grid that essentially serves as an “add-on” facilitating the reliable movement of power from generation sited close to load? In other words, should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its

³⁷ See *Regional Transmission Organizations*, Order No. 2000, [1996-2000 Regs. Preambles] F.E.R.C. Stats. & Regs. ¶ 31,089, at 31,014-15 (1999), *order on reh'g*, Order No. 2000-A, [1996-2000 Regs. Preambles] F.E.R.C. Stats. & Regs. ¶ 31,092 (2000), *appeal dismissed*, *Pub. Util. Dist. 1 v. FERC*, No. 00-1174 (D.C. Cir. 2001).

³⁸ See remarks of Jeff Wright, Director of the Infrastructure Division of the Office of Economic Projects, Tr. at 49-51. Mr. Wright further noted: “Air quality may limit coal-fired electric development in these nonattainment areas, however, the non-attainment areas, for the most part do not overlap coal production areas. This lends credence to the idea of constructing more mine-mouth generation plants and transporting that energy to where it is needed.” *Id.* at 49. See also Chairman Wood, Tr. at 13 (“[T]he future coal plants in our country, and the existing coal plants, tend to be located relatively remotely from where they’re being used, at least in part, and so to enable that power to get from where it’s generated to where it’s consumed, it’s important to have a strong and robust delivery system.”).

³⁹ Zibelman Written Remarks at 5.

design, links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose? The “rules of the road” and costs to build one system versus another are vastly different....

In many ways, the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry. ... Assuming that we wish a strong transmission system to provide load with many options, we believe a new set of “building blocks” is needed.⁴⁰

While many reasons contribute to the lack of transmission investment,⁴¹ one is an unintended side effect of the creation of RTOs: diffuse responsibility and lack of accountability for ensuring an adequate grid. Under Order 888, transmission providers were responsible for planning and improving their systems to assure that our firm transmission service was as reliable as the service they provided to their own native load customers, and faced consequences for failing to do so: load ratio sharing of redispatch charges. Transmission owners that have turned over control of their transmission systems to RTOs no longer feel responsible for planning and expanding those networks, and (as discussed in Part VI below) LMP pricing eliminates the consequences for failing to make upgrades needed by others. Nor are RTOs accountable for failing to do so.

A further contributor to the ever-more-congested RTO grid is the move away from use of load-specific deliverability for assessing network resource designations. Under Order 888, LSEs were required to pass a source-to-sink deliverability test to

⁴⁰ *Id.*

⁴¹ See TAPS White Paper “Effective Solutions for Getting Needed Transmission Built at Reasonable Cost” (June 2004), *available at* <http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf> (last viewed June 24, 2005).

designate a network resource. In the RTO context, the Commission has abandoned this standard, instead substituting an “aggregate” deliverability test.⁴² Eliminating specific deliverability requirements breaks the crucial link between LSE resource planning and RTO transmission planning and expansion. In effect, the Commission is saying that physical delivery of resources to load is irrelevant because RTO markets with locational pricing will accomplish delivery through redispatch, *i.e.*, out-of-merit order dispatch.⁴³ This heavy reliance on redispatch relieves RTOs of the need to plan and upgrade the transmission system to create the physical capacity to assure that LSE resources are and continue to be deliverable on a source-to-sink basis. However, at the same time RTOs are abandoning specific deliverability for network resource designations, they are relying a more extreme version of the test – simultaneous feasibility – to assess the availability of FTRs required to hedge congestion.

RTO planning processes need to be modified so they achieve Order 2000’s intent. RTOs must plan for the robust grid required for wholesale competition, not a minimalist grid where load is served from local generation. RTOs must resolve bottlenecks that burden consumers with high prices and create the transmission highways required for the

⁴² Order 2003 provided for aggregate deliverability for Network Resource Interconnection Service, which provided rights for network resource treatment. *Standardization of Generator Interconnection Agreements and Procedures; Notice of Proposed Rulemaking*, 67 Fed. Reg. 22,250, 22,266 (NOPR IA § 4.1.2.3) (May 2, 2002). In the RTO context, the Commission has gone a step further and substituted aggregate deliverability as the standard for network resource designation under Network Integration Transmission Service. *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 109 F.E.R.C. ¶ 61,157, PP 309, 312, 321 (2004), *Order on Rehearing and Compliance Filings*, 111 F.E.R.C. ¶ 61,043 (2005); *Midwest Independent Transmission System Operator, Inc.*, 109 F.E.R.C. ¶ 61,285, PP 292-99 (2004), *Order on Rehearing and Compliance Filings*, 111 F.E.R.C. ¶ 61,053, PP 152-54 (2005).

⁴³ Recent data on aggregate deliverability in MISO indicates that approximately 88% of the generation fleet in the MISO footprint is available for designation as a network resource throughout the region. *See* http://www.midwestiso.org/plan_inter/gen_deliver_test_results.shtml. This apparently means that an entity in the MAPP area, such as Montana Dakota Utilities, could designate all of its network resources from Ohio or Kentucky if it wished.

next generation of baseload coal (and nuclear) generation – the types of generation that have traditionally driven transmission development – and associated long-term rights to support investment in those plants.

This will require discarding misguided efforts to limit RTO planning to “reliability” upgrades, as opposed to “economic” upgrades.⁴⁴ The key is to provide loads with access to competitive markets. Economically beneficial upgrades should be made. Regional transmission plans must accommodate future load growth; and the RTO transmission planning horizons should reflect realistic processes for siting and constructing transmission.⁴⁵ RTOs need clear authority to mandate transmission construction by TOs or otherwise,⁴⁶ with accountability for failure to follow through.

The robust grid that results from such revamped planning and expansion should largely take care of the need to support the limited long-term transmission rights defined above. However, as a further check and particularly in the transition, a load-specific deliverability test for network resource designation should be reinstated at least for eligible resources for which long-term rights are sought, to determine whether the rights are initially simultaneously feasible. Further, for those resources that obtain long-term

⁴⁴ As explained at the Coal Transmission Technical Conference by National Grid’s Paul Halas, “Every transmission investment will have impacts on both reliability and economic efficiency.” Tr. at 77-78.

⁴⁵ As discussed in n.29 above, PJM is moving to a ten-year planning process. *See also* Infrastructure Division Director Jeff Wright’s comment at the Coal Transmission Technical Conference, Tr. at 52 (“[I]t can take almost three times as long to construct a bulk transmission line, than it is to build a new coal-fired generation plant”).

⁴⁶ The “consortium approach” being explored by PJM is consistent with the inclusive transmission investment models advocated in the TAPS White Paper. *See* testimony at the Coal Transmission Technical Conference of PJM’s Karl Pfirrmann, Tr. at 68 (through the consortium concept, “public power entities who have long expressed interest in ownership of transmission facilities, can now be partners in such a project”); and TAPS member Gayle Mayo of Indiana Municipal Power Agency, Tr. at 163-64 (public power entities have money they are willing to invest in transmission, whether its formal joint ownership or a consortium approach).

rights, load-specific deliverability sufficient to support the continued simultaneous feasibility of those rights, taking into account of other rights (e.g., existing rights) that require preservation, must be maintained as part of the “base plan.” It is reasonable for the grid to be planned to accommodate 24x7 dispatch of baseload resources, with appropriate consideration accorded to the more limited long-term rights (discussed above) for renewables. As discussed below, such treatment is consistent with the planning obligations traditionally borne by transmission providers under Order 888.⁴⁷

V. WHO PAYS FOR TRANSMISSION UPGRADES?

TAPS’ approach to long-term rights is closely tied to the planning process and assumes expansion of the grid to support those rights, as well as a robust competitive market. How should that expansion be paid for? A number of approaches make sense. However, whatever cost allocation method is adopted for the upgrades required to support initial assignment of a long-term right, future upgrades (if any) required to maintain the simultaneous feasibility of these rights over time and upon renewal should be “rolled in” (or regionally assigned), rather than directly imposed on the entity with the long-term right. This treatment is consistent with Order 888, which requires the transmission provider to plan and expand the system to accommodate service from network resources to network load, without repeatedly placing the customer on the margin.

⁴⁷ Indeed, in the context of the Entergy ICT proposal, under which customers would be required to participant fund costs associated with supplemental upgrades, the Commission made clear that “Entergy bears the burden of defining long term firm transmission rights which protect the customer from any future ‘congestion’ costs associated with re-dispatch generation and must protect the customer from curtailment except in a force majeure situation.” *Entergy Services, Inc.*, 111 F.E.R.C. ¶ 61,222, P 15 (2005).

The best approach to funding major upgrades is some form of regional rate, where costs are assigned to reflect regional benefits, rather than either assigned to the “license plate” service territory where they are incurred or assigned on a participant funded basis to individual market participants. Due to the dynamic and highly integrated nature of the AC grid, high voltage, backbone transmission lines provide benefits beyond the immediate geographic area where they are constructed. In recognition of this fact and to respond to one of the major criticisms of “license plate” pricing (where a subset of customers benefited by such lines must bear the entirety of their costs), the Commission should assign the costs of major backbone facilities across regional (and/or, in very large RTOs, subregional) load. Broadly spreading “highway” transmission costs not only will match cost imposition to those who benefit, including remote beneficiaries of a grid upgrade, but also will reduce each consumer’s burden and therefore resistance to construction. Many speakers at recent technical conferences stressed that the best way to promote transmission expansion was to move away from license plate rates and toward a regional approach.⁴⁸

The TRANSLink proposal⁴⁹ addresses both the need to spread the costs of regionally significant upgrades and the problem of unfairly burdening an area with

⁴⁸ See, e.g., AEP’s Mike Morris (Tr. at 188) and National Grid’s Paul Halas (Tr. at 76) at the May 13 Coal Transmission Technical Conference. At the April 22 Transmission Investment Technical Conference, Trimaran Capital Partners’ John Larson suggested that investment would be promoted by a tariff that does not assign all the costs of new transmission lines to the footprint where it is built (Tr. at 53-54). Because regional rates can deal effectively with the equity issues associated with transmission investment, a number of participants at that conference advocated regional rates, including Roy Thilly (Wisconsin Public Power Inc. on behalf of TAPS), Tr. at 283. See also TAPS White Paper “Effective Solutions for Getting Needed Transmission Built at Reasonable Cost” at 19-20 (June 2004); Post-Technical Conference Comments of the Transmission Access Policy Study Group, filed in *Transmission Independence and Investment*, Docket Nos. AD05-5-000, PL03-1-000 (May 2, 2005).

⁴⁹ The approach is described in *TRANSLink Transmission Co., L.L.C.*, 99 F.E.R.C. ¶ 61,106, at 61,465-68 (2002), and *TRANSLink Development Co., L.L.C.*, 101 F.E.R.C. ¶ 61,316, PP 15-24 (2002).

transmission costs for generation built to serve load in other areas, better aligning transmission pricing to cost causation. Under the TRANSLink rate design, the costs of regional highway facilities would be spread to everyone in the region, and the costs for the local area grid would be paid by both load and generation in the local area. Similarly, in New England, the Commission has approved recovering the costs of “Pool Transmission Facilities” (or “PTF”) on a region-wide basis because of their “diffuse network benefits,” while the costs of “non-PTF” facilities are recovered on a local system basis.⁵⁰

Recently, the Commission largely approved SPP’s cost allocation methodology, which provides for recovery of one third of the costs of “Base Plan” through a postage-stamp rate paid by all users of the SPP system, with the other two thirds assigned to affected zones.⁵¹ While TAPS members have concerns about the limits on the network resource-related upgrades to which Base Plan treatment applies⁵² and the direct assignment of costs that do not qualify for such treatment, the SPP cost allocation provides an example of a Regional State Committee-developed regional cost allocation.

Failure to spread the costs of regionally significant facilities is likely to cause needed transmission not to be built because of objections from those who would be

⁵⁰ *New England Power Pool*, 105 F.E.R.C. ¶ 61,300, P 25 (2003).

⁵¹ *Southwest Power Pool, Inc.*, 111 F.E.R.C. ¶ 61,118 (2005).

⁵² For such costs to receive Base Plan treatment: (i) the customer must have at least a five-year commitment to the designated network resource (“DNR”), (ii) the addition of the DNR must fit within a capacity level equal to 125% of the customer’s peak load, and (iii) the costs of the new transmission facilities needed for the DNR for which Base Plan treatment will apply are capped at a “safe harbor” limit of \$180,000/MW . SPP allows a network customer whose DNR upgrade does not meet all of these criteria to seek a waiver so that some or all of its costs can be accorded Base Plan treatment. In accepting the SPP proposal, the Commission made clear that it shared concerns raised by some TAPS members regarding the impact of these restrictions and required further assessments and reports. *See Southwest Power Pool, Inc.*, 111 F.E.R.C. at PP 51-52.

unfairly assessed its entire costs, or cause facilities to be built at less-than-optimal size in order to make them more affordable.

To the extent costs of the initial upgrades, if any, required to support the new long-term rights are not assigned on a regional or subregional basis, “or” pricing would be appropriate. The D.C. Circuit has long confirmed the soundness of the math underlying this approach,⁵³ which is especially appropriate in connection with the long-term commitment to take and pay for transmission service associated with long-term rights. (As noted above, however, future upgrades to maintain financial feasibility should be rolled in; a customer should not be placed on the margin more than once.)

Participant funding, which localizes upgrade costs on individual market participants, is not the answer. This mechanism is poorly adapted to a dynamic AC grid, where “lumpy” upgrades assigned to a single project may provide benefits to many market participants, specific beneficiaries are difficult to identify and change over time, and benefits can be enjoyed by “free riders” (*i.e.*, entities other than the funding entity).⁵⁴

Participant funding invites a game of chicken where would-be beneficiaries sit back in the hope that others will step forward to bear the cost of an upgrade. Meanwhile, transmission construction and the associated benefits to consumers are delayed. At a time when getting transmission built promptly is imperative, it is unwise to rely on a

⁵³ See *Pennsylvania Electric Company v. FERC*, 11 F.3d 207 (D.C. Cir. 1993) (*Penelec*).

⁵⁴ See, e.g., testimony of ITC’s Joe Welch at the April 22 Transmission Investment Technical Conference: “One proposed solution to this problem is participant funding. However, this proposal does not work because it likely will result in a suboptimal expansion of the grid. Not to mention the ‘free rider’ effect where those who benefit from the expansion don’t have to pay. In addition, participant funding may not be consistent with the independent transmission company model.” Tr. at 81.

mechanism that has produced disappointing results even in PJM.⁵⁵ Participant funding's justification of upgrades based on private benefits to specified market participants, rather than the public benefits typically required to obtain state approval, will make the difficult state transmission siting process even harder.⁵⁶

VI. WHO BEARS THE RISK OF THE SYSTEM BEING INADEQUATE TO SUPPORT THE LONG-TERM RIGHTS?

As noted above, in the Order 888 world, the Transmission Provider had a clear obligation to plan and expand the system to accommodate new firm transmission service requests and new network resources.⁵⁷ Once firm service is granted, the transmission provider is obligated to maintain and expand its system to support such service, or must share the pain. In the event redispatch is required to maintain firm service, the transmission provider is required to redispatch its own and the network customer's resources, with cost-sharing on a load ratio basis.⁵⁸ Curtailments are required to be non-discriminatory as among firm point-to-point, network, and native load customers.⁵⁹ Thus, the transmission provider and its native load customers had "skin in the game." In the event the transmission provider expanded the system on an ongoing basis to support the firm service granted as well as load growth, the transmission provider's native load customers (like all other users) shared in the cost. In the event the transmission provider failed to maintain the system to support firm service it had granted, its native load

⁵⁵ Zibelman Written Remarks at 5.

⁵⁶ To the extent, over TAPS objections, some form of a participant funding approach is adopted for the initial upgrades required to support long term rights, the funder should be assigned FTR options, not obligations. In this context, there is no basis to put the funder at risk by assigning an FTR obligation.

⁵⁷ See OATT § 28.2.

⁵⁸ See OATT §§ 33.2-33.3.

⁵⁹ See OATT §§ 13.6, 33.4.

customers would absorb the lion's share of the associated redispatch costs.⁶⁰ The Order 888 tariff's built-in accountability mechanism gave meaning to the transmission provider's obligation to plan and expand its system.

The OATT's accountability mechanism got lost in the transition to RTOs with LMP markets. Instead of assigning redispatch costs to the load in the pricing zone that would bear the cost of upgrades that would relieve the constraint, RTOs with LMP markets directly assign congestion costs to the specific LSEs whose resources are removed from their loads, on the theory that these entities (who may well have secured their firm transmission rights years ago) are now "causing" the congestion. Not only is the transmission owner relieved of responsibility for the ongoing costs of any past failures to plan and expand the system to accommodate the firm service it granted in pre-RTO days, but the RTO itself takes no responsibility to ensure sufficient FTRs to offset congestion associated with either historical or new network resources.

Accountability must be restored. Unless transmission owners step forward to bear the risks⁶¹ or a TO fails to follow through in good faith to construct facilities it is assigned by the RTO to construct, the costs of failure of the grid to support the long-term rights granted should be broadly shared either throughout the RTO (which has the planning responsibility), or at least those in the pricing zone(s) that would bear the costs of upgrades required to fully support the long-term rights on a simultaneously feasible basis. This treatment is particularly appropriate where TAPS is advocating new long-

⁶⁰ These costs typically would be flowed through the retail fuel adjustment clause.

⁶¹ Transmission rights could be created by transmission owners, who would charge prices sufficient to cover their expected costs (including the costs of their risk). Transmission owners could back up the transmission rights that they create by paying subsequent congestion costs or by building new transmission facilities.

term rights for only a subset of new resource commitments, and our preferred structure, Dispatch-Contingent FTRs, would reduce the RTO's payment obligation by limiting it to those hours when the generator is running.

Under Order 2000, the RTO is the entity with the planning and expansion responsibility. It is both necessary and appropriate to hold the RTO responsible for at least meeting this planning and expansion responsibility as to those resources that qualify for long-term rights. However, because a non-profit RTO is pocketless, it cannot be directly held accountable for failing to meet its planning and expansion obligation. By assigning the costs through an identified uplift, the cost of the RTO's planning failure can be compared to the upgrade costs so a form of accountability can be reinstated. Further, by assigning cost responsibility for congestion associated with long-term rights in a manner consistent with cost responsibility for the upgrades that would be required to avoid such costs, the Commission would foster a consensus in favor of making needed upgrades, rather than encouraging delay.

In contrast, it would be unfair and inappropriate to saddle long-term right holders – those who have made generation investments in reliance on the long-term rights, but have no control over transmission expansion decisions – with the costs of the RTO's failure to plan and expand the grid to maintain those rights on a simultaneously feasible basis. If the long-term rights holders were subject to prorationing in the event the grid is not expanded sufficiently to support the continued simultaneous feasibility of those rights, the RTO (and the transmission owners) would be relieved of accountability for planning and expansion decisions. Such a regime would all but invite opposition to upgrades that would be more broadly assigned. Thus, it would play right into the hands

of those who benefit from a minimalist grid, with maximum congestion and opportunity for the exercise of market power.

VII. TAPS' PROPOSAL ADDRESSES THE IMPEDIMENTS TO LONG-TERM RIGHTS IN RTO MARKETS

The Staff Discussion Paper identifies five potential impediments to long-term financial rights in RTO markets: (1) uncertainty about future changes in the transmission network and major generation resources (Staff Paper at 8); (2) unpredictable congestion prices and patterns (*id.*); (3) creditworthiness of market participants who hold long-term financial rights or seek to purchase them at auction (*id.* at 9); (4) concern that long-term rights will tie up valuable hedging instruments, thereby becoming a barrier to entry in retail competition states where LSEs tend not to seek transmission rights beyond the terms of their energy contracts (*id.*); and (5) concern that long-term FTRs may be less liquid than annual or shorter-term FTRs, resulting in a less efficient market for congestion hedges (*id.*). TAPS' proposal overcomes all of these impediments by giving RTOs the tools they need to eliminate risk and uncertainty, and by limiting the resources for which long-term rights would be granted to LSEs.

The first three impediments identified by Staff boil down to a concern that issuing long-term FTRs is too risky for RTOs because of the inherent unpredictability of LMP markets. Not issuing long-term rights, however, does not eliminate that underlying risk—it just shifts it to LSEs seeking to invest in generation that benefits the region but cannot be constructed near the LSE's load (*e.g.*, baseload coal, nuclear, and renewable generation), and in particular to LSEs who do not have the power to fix the transmission problems that contribute to price volatility in LMP systems.

The solution to handling the uncertainties associated with long-term transmission rights is not to play hot-potato with the risk, but to give RTOs the tools they need to reduce or eliminate congestion pricing risk by fixing the bottlenecks that cause congestion: *i.e.*, a strong transmission planning obligation, coupled with the authority to mandate construction of transmission facilities for both reliability and economic purposes. TAPS' proposal, which would require RTOs to plan and construct upgrades to support the continuing simultaneous feasibility of long-term rights, would place responsibility where it belongs and restore one of the fundamental elements of grid planning—the link between baseload plant construction and transmission expansion.

TAPS' approach also addresses the FTR market liquidity concerns identified in the Staff Paper. Our proposal is narrowly tailored to address the generation investment disincentives created by the LMP system, so eligibility for long-term rights would be limited to new baseload and renewable resources. The remaining transfer capability (beyond that required to preserve existing rights in accordance with the White Paper) would still be available for shorter-term FTRs. Particularly if the Commission assures that RTOs have a mandate to strengthen regional transmission networks over time, the resulting robust grid should be able to accommodate both long-term and shorter-term (*e.g.*, annual) FTRs.

Finally, the fact that long-term rights may not be attractive to certain LSEs subject to retail competition should not deprive those who retain an obligation to serve of the opportunity to plan for their needs and invest in generation that will broadly benefit consumers. As noted above, for LSEs subject to retail competition, new capital-intensive generation like new clean coal and nuclear units will not be financed in the absence of

PUC-assured rate recovery.⁶² If some LSEs in retail competition states are unwilling and unable to make long-term commitments and choose to rely exclusively on short-term transactions to serve their loads, and that is acceptable to their state PUCs, then they should be free to do so. However, this choice should not deprive all consumers of the benefits of baseload generation that depends on long-term commitments and associated long-term rights.

Many states have chosen not to adopt retail competition; even in states that have adopted retail competition, some LSEs, including public power systems and rural electric cooperatives, still have an obligation to serve. These LSEs must have access to the full set of tools needed to assemble cost-effective, fuel-diverse power supply portfolios over the long-term. The argument that they should be denied those tools in order to maximize the availability of short term rights is tantamount to saying, in an Order 888 world, that a transmission provider should not be able to grant long-term firm transmission service, or accept long-term resource designations for its native load or a network customer, because that will tie up the short term capacity otherwise available to those who choose not to make a long-term commitment. In a capital-intensive industry that, as Wall Street confirms,⁶³ requires long-term contracts, a lowest-common-denominator policy approach is bad policy and contrary to the Administration's goals of encouraging the construction of new clean coal, nuclear, and renewable resources.

⁶² See testimony of AEP's Mike Morris at the Coal Transmission Technical Conference, Tr. at 230.

⁶³ See pages 9-10 above.

CONCLUSION

Our country's economic viability and security depends on new investment in fuel-diverse and renewable generation that cannot be located close to load centers. Investment in such generation requires long-term rights to assure deliverability at a reasonable, predictable cost. The short-term focused market design the Commission has adopted in some RTOs creates challenges that must be overcome to define, plan for, and fund those rights. TAPS has outlined several long-term rights models that meet these challenges and can work in conjunction with LMP markets. In our view, the Commission does not have a legitimate policy option to stick with its existing short term approach; whatever the challenges posed by LMP market designs, the Commission cannot avoid its obligations to provide for the long-term rights necessary to ensure just and reasonable wholesale power rates, consistent with the Act. TAPS looks forward to working with the Commission to make these long-term rights a reality.

Respectfully submitted,

/s/ Cynthia S. Bogorad

Robert C. McDiarmid
Cynthia S. Bogorad
William Huang

Attorneys for
Transmission Access Policy Study
Group

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

June 27, 2005

Attachment A

May 31, 2005

Dear PJM Members and Interested Stakeholders,

The PJM Board of Managers extends its sincere appreciation to all Members and Interested Stakeholders for their valuable input and dialogue on the Reliability Pricing Model (RPM) and on proposed enhancements to the Stakeholder processes, as well as the other matters addressed at the Annual Meeting. The Board is now in the process of evaluating how best to proceed with the current RPM proposal. In this letter, we update the Members on the Board's current thinking with respect to RPM and the Stakeholder processes.

As you may be aware, FERC has convened a technical conference on RPM on June 16, 2005. In light of significant difference of opinion on many aspects of RPM, the Board understands and welcomes FERC's interest in supporting PJM and its Members' efforts to reach a satisfactory resolution of this challenging topic. Thus, as a preliminary matter, the Board has elected to defer a decision on the RPM proposal until it has had a chance to consider the record which will develop during the FERC Technical Conference.

The Board also notes that the RPM proposal focused principally on establishing a longer-term generation commitment to facilitate the attraction and retention of generating capacity required for system reliability. The comments that we have received over the last year and particularly during the Annual Meeting crystallized the important perspective that an adequate capacity market cannot be developed in a vacuum. Rather, capacity solutions must be integrated with transmission planning and the development of robust demand side alternatives. For these reasons, and independent of the direction PJM ultimately may take with regard to RPM, the Board is directing PJM to undertake the following initiatives:

1. **Long term transmission planning** – The Regional Transmission Expansion Process (RTEP) currently uses a five-year planning horizon. It has become apparent that the level and nature of transmission investment required for the region requires a longer time period. The Board is directing PJM to work with the Membership to develop protocols for establishing a ten-year planning process by year end.
2. **Economic Planning** – The Board is concerned that PJM's current methodology for economic planning may not be achieving the desired outcome of ensuring adequate transmission investment to support robust competitive markets. The Board is directing PJM to review its current economic planning process and work with the Members to identify appropriate changes. To the extent feasible, PJM will undertake this analysis in conjunction with the development of the longer term planning process.
3. **Long-term FTRs** – The Board understood the concern of a number of Stakeholders that the absence of long-term FTRs is impeding transmission investment and the development of long-term bilateral capacity contracts. The Board understands that FERC has commenced a proceeding on this topic. The Board is appreciative of this initiative and will encourage timely completion of PJM's efforts in this regard.

4. **Demand Response** – PJM currently has several initiatives, including RPM, to integrate demand response programs into its markets and to expand the usage of demand response in the wholesale market. The expectation is that these initiatives will be filed with FERC by year-end. PJM is also working with its States to identify and resolve regulatory and other impediments to maximum participation of load in the markets. In this regard, the Board applauds the efforts of the States and the Membership and encourages their timely completion.

5. **Near-term generation and transmission adequacy and reliability requirements** – The RPM analysis revealed significant reliability concerns in Northern New Jersey beginning in 2008. Regardless of how RPM proceeds, the Board is convinced that these issues must be resolved expeditiously. The RTEP processes have already identified the near-term transmission requirements for these regions. The Board also understands that PJM and the transmission owners are taking the necessary steps to invest in and secure the reliability of the local grid. The Board will continue to monitor these efforts. In addition, the Board is directing PJM to work with the State of New Jersey and affected generation owners and load representatives to ensure that the appropriate contracts are in place to retain adequate generation in the region as well as to explore avenues to optimize the availability of demand response.

Finally, the Board is encouraged by the Members' response to the PJM Whitepaper which suggested modifications to the current Stakeholder process. The Board is pleased with the formation of a working group to address this topic and looks forward to the results produced by the group.

In closing, the Board appreciates the members' dedication to improving the PJM markets. As the PJM markets mature and the Membership increases, there will remain many opportunities to find and implement market design changes that will enhance the ability of the markets to meet electric customer needs. In almost every instance, there will be differences of opinion and new approaches to resolve the identified problems. As in the case of RPM, the Board believes that debate among the Members will improve the quality of the final product and identify other opportunities to improve reliability and market participation. The Board will continue to consider the RPM proposal and will inform the Members of its decision at the earliest possible opportunity, taking into account in its deliberations the record of the Commission's technical conference.

Sincerely yours,

Phillip G. Harris on behalf of the PJM Board

PGH/AAZ/cf/gks