ORGANIZATION OF MISO STATES, INC.
SPECIAL BOARD MEETING MINUTES
June 22, 2005

Approved 8/11/05

Commissioner Kevin Wright, President of the Organization of MISO States, Inc. (OMS), called the June 22, 2005 Special Meeting of the OMS Board of Directors to order at the Peabody Hotel in Little Rock, Arkansas at approximately 12:45 p.m.(cdt). The following directors were present for the meeting:

Susan Wefald, North Dakota
Steve Gaw, Missouri
Bob Nelson, proxy for Laura Chappelle, Michigan
David Sapper, proxy for Robert Garvin, Wisconsin
Diane Munns, Iowa
Kevin Wright, Illinois
David Hadley, Indiana
A.W. Turner, proxy for Mark David Goss, Kentucky
Ken Nickolai, Minnesota
Greg Jergeson, Montana
Judy Jones, Ohio
Kim Pizzingrilli, Pennsylvania
Rolayne Wiest, proxy for Gary Hanson, South Dakota

Absent: Manitoba
Nebraska

<u>State Commission Members Present:</u>

Eric Witle, Minnesota	Andy Tubbs, Pennsylvania
John Smith, South Dakota	Jan Karlak, Ohio
Candace Beery, Montana	Burl Haar, Minnesota
Randy Rismiller, Illinois	Bill Vanderlaan, Illinois
Frank Bodine, Iowa	Bill Smith, OMS Staff

<u>Industry Members Present:</u>

Doug John - Counsel for MSATs
Tom Wrenbeck - Independent Transmission Co.
Julie Voeck - American Transmission Co.
Joe Bambenek - METC
Warren Day - American Transmission Co
Peggy Ladd - Ameren
Sherman Elliott - MISO
Dave Svanda - Svanda Consulting
Tom Brause - Ottertail Power
Don Ball - Montana Dakota Utilities
John Kozyrski - MISO
Dick Lahey - PJM Board
Jean Kinsey - PJM Board
Richard Mathias - PJM
Joe Bowring - PJM

The Directors and proxies listed previously established the necessary quorum for the meeting of at least eight Directors being present.

President Wright opened the meeting by welcoming guests from the Board of Managers of PJM - Dr. Jean Kinsey and Dr. Dick Lahey. He then announced that there would be one item of new business on the agenda.

Action item: Consideration of OMS Draft Comments to FERC on Long Term Transmission Rights in Markets with Locational Pricing, Docket # AD05-7

Mike Proctor, chair of the Congestion Management & FTR Allocation Work Group, was not available to explain the comments. Steve Gaw presented the draft for Mike Proctor. Jan Karlak indicated there would be amendments coming from Ohio that she would email to the OMS board. President Wright also indicated amendments from Wisconsin he had received, should also be distributed to the board. John Harvey, co-chair of the work group, indicated he had not seen the amendments from either state.

President Wright indicated that although the comments are due June 27, Bill Smith felt confident OMS could seek a filing extension from the FERC.

It was moved by Ken Nickolai and seconded by Bob Nelson to ask the FERC for an extension to consider and review the proposed comments and amendments with the intent to have an open meeting on June 30 to formally consider the comments. A voice vote was taken and the motion carried by a majority of the directors present.

At this time, President Wright began discussion of the comments as drafted and asked for explanation of the two state amendments. John Harvey offered highlights of the comments as drafted by the Congestion Management & FTR Allocation Work Group. After David Sapper explained the changes offered by Wisconsin in their amendments, John Harvey felt some might not be accepted by the work group. Jan Karlak and Judy Jones did not feel Ohio's amendments were substantive changes, but were necessary for approval.
Steve Gaw then referred to a phrase concerning "physical scheduling rights" on page 7 that would concern MO. President Wright then reminded the directors that any further changes should be brought to the working group.

President Wright thanked those who explained amendments and charged the work group with incorporating changes into another draft to be discussed and voted on June 30 at a Special Board of Directors meeting.

At this point in the meeting, Diane Munns asked for a point of personal privilege by announcing that this would be the last OMS Board of Directors meeting for Bob Nelson of the Michigan Commission. She asked the OMS Board to recognize Bob for all his help to the OMS. Diane also indicated this meeting would be her last as well. She explained that her tenure at NARUC is taking more and more of her time, and that Chairman John Norris of the Iowa Utilities Board will be assuming her OMS responsibilities. President Wright was eloquent in his description of the value Diane and Bob brought to OMS. Susan Wefald echoed his sentiments.

At this point in the meeting, the OMS directors were given the following presentations:

<u>At 1:30 pm</u>
"The Stand-Alone Business Model" presented by Julie Voeck of American Transmission Company and Joe Bambenek of Michigan Electric Transmission Company

A copy of this presentation is attached to the end of the minutes.

<u>At 2:30 pm</u>
"Early Report on the State of the Midwest Energy Market" presented by David Patton, Potomac Economics, Market Monitor

A copy of this presentation is attached to the end of the minutes.

Announcements:
The next OMS Board of Directors meeting is Thursday, June 30 at 2:00 pm CDT.

Meeting adjourned at 3:45 pm (cdt)

FINAL DRAFT June13, 2005

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Long Term Transmission Rights in Markets Operated by Regional Transmission Organizations and Independent System Operators	))))	Docket No. AD05-7-000

ORGANIZATION OF MIDWEST ISO STATES COMMENTS ON ESTABLISHING LONG TERM TRANSMISSION RIGHTS IN MARKETS WITH LOCATIONAL PRICING

I. Background

On May 11, 2005, the Federal Energy Regulatory Commission (FERC) issued a Notice Inviting Comments on Long-Term Transmission Rights. In its notice, the FERC characterized the concern as one that has been raised by some market participants regarding their inability to fully hedge market prices from resources that they may own or have under contract. In this context, a hedge is the ability for the load-serving entity to keep the price for serving load at the cost of operating resources owned or under long-term contracts (i.e., Designated Network Resources (DNRs)) and short-term contracts for economy transactions.

In regions of the United States where Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs) either do not exist or do not use Financial Transmission Rights (FTRs),[1] the issue of hedging is dealt with via the deliverability of power from generation sources to native load using "physical" transmission rights – the right to inject power from a generation source to serve native load. In particular, Network Service is defined as transmission service from a load-serving entity's DNRs to its native load.[2] Specifically, once the Transmission Provider approves a load-serving entity's DNRs, it is the obligation of the Transmission Provider to make the upgrades necessary for the load-serving entity to continue to be able to deliver the power from those DNRs. It is important to recognize that physical transmission rights never constituted an absolute ability to flow a particular transaction all hours

[1] For example, the Southwest Power Pool (SPP) is a FERC-approved RTO that does not plan to use FTRs to manage congestion in its proposed real-time energy imbalance market.

[2] For hedging the price of short-term bilateral contracts, the load-serving entities can also arrange delivery via requests for short-term, point-to-point service.

of the year. Specifically, there are times when deliverability from the most economic resources may be restricted because of transmission constraints and more expensive generation must be dispatched to meet those constraints; i.e., redispatch is required to maintain power system reliability. In addition, all physical transactions are subject to curtailment using Transmission Line Loading Relief (TLR) in the event that allowing schedule transmission flows would otherwise violate the security constraints and threaten the reliability of the power system. A TLR event can curtail firm service from DNRs when the curtailment of non-firm service does not alleviate the threat to the grid.

What is described above as a hedge through physical deliverability is not the case for RTOs and ISOs that have adopted the use of FTRs. While holding an FTR from a DNR will assure the load-serving entity that it can hedge its cost from that generation source, a load-serving entity is not assured that it will be allocated FTRs from its DNRs for its entire load. For example, in the FTR allocation process at the Midwest ISO, load-serving entities are assigned Candidate FTRs (CFTRs) from each of their DNRs and the Midwest ISO performs an annual allocation by which the load-serving entities are allowed to nominate FTRs from their CFTRs in a series of four tiers that add up to their forecasted summer peak demand. Not all CFTRs nominated will necessarily be allocated to the load-serving entities because of a requirement that all allocated FTRs be simultaneously feasible.[3] In the Staff Discussion Paper on Long-Term Transmission Rights Assessment (May 11, 2005), the issue is described as follows:

> "Some market participants have concerns that sufficient transmission rights may not be available each year to adequately cover their congestion cost exposure. They argue that the combination of potentially volatile congestion costs, variability in the annual allocation, and the inability to secure a known quantity of transmission rights for multiple years introduces an unacceptable degree of uncertainty into resource planning and investment. As a result, some participants want the ability to obtain long-term transmission rights or service at a price certain."[4]

As a general matter, the OMS supports the desire by all market participants to develop approaches that will reduce market risks from congestion costs. However, this issue is somewhat

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[3] This requirement is necessary in order to maintain expected revenue adequacy for the RTO/ISO; i.e., to ensure that the RTO/ISO expects to collect sufficient revenues in congestion cost payments to pay out to the FTR holders.

[4] Long-Term Transmission Right Assessment, FERC Staff Discussion Paper, p.1.

more complex than it might first appear. Specifically, the more traditional view of resource planning involving building generation plants that will serve a specified load or service territory for the life of the plant, is different from the perspective where multiple load-serving entities use shorter-term contracts to serve retail load on a competitive basis. In competitive markets, market participants may determine that the risks associated with longer-term commitments are unacceptable because of the lack of certainty regarding the load that they will be serving. These two perspectives imply that purveyors of each of these different perspectives will have a desire to hedge power supplies for significantly different forward time periods. The Midwest ISO provides a footprint that encompasses the traditional perspective of state-regulated, vertical utilities, the restructured paradigm in which generation supply is a competitive resource and systems that have divested transmission assets. These comments of the Organization of MISO States (OMS) have attempted to address the issue of long-term financial transmission rights from all of these diverse perspectives.

II. Summary of Comments

The need to decrease the risk associated with congestion costs appears to be a general concern that is cognizant of credit ratings, and the costs to market participants and ultimate consumers. With the needs for more capital intensive investments by utilities to perform environmental upgrades to existing facilities, the demands for replacing older capacity, the demands for additional base-load capacity, and the need for transmission system enhancements, initiating a discussion at the federal level addressing these needs and concerns through long-term transmission rights or other means is timely and welcomed.

In response to the notice inviting comments regarding long-term transmission rights, the OMS is submitting detailed comments. The following highlights the primary points of the more detailed discussion.

- To guarantee long-term transmission rights absent grid expansion may mean shifting the congestion costs among market participants without lowering the overall level and therefore risks of these congestion costs. This does not mean that the FERC should abandon consideration and potential implementation of long-term FTRs.
- Longer-term transmission rights that are not subject to prorating require a higher risk premium (potentially much higher) than shorter-term transmission rights that are subject to prorating. This is because the longer the term for which risks are to be mitigated, the greater the amount of uncertainty and the higher the cost of mitigating

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that risk. Given that OMS is not aware of any proposals or practical ways to set a higher premium, there is no strong argument for exempting long-term FTRs from experiencing a pro-rata share of revenue shortages.

- At this time physical scheduling rights are not necessary, nor particularly desireable. If some form of reverting to physical rights is used to address the establishment of long-term transmission rights, it should not occur at the expense of reduced efficiency to the RTO day-ahead and real-time energy markets
- A properly executed regional planning process, including siting with appropriate cost allocation for reliability and regionally beneficial upgrades to the transmission system, is likely the most important factor in reducing congestion costs in the long term.

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III. Detailed Comments on Long-Term Transmission Rights Assessment

A. The Interest in Long-Term Transmission Rights

The FERC Staff's well-written Discussion Paper refers to some market participants' perception of greater price risk because of volatility of the congestion cost component of locational marginal pricing (LMP) or "congestion cost risk" as well as the desire to diminish this risk when financing new generation and transmission investment.[5] FERC Staff notes that, while not all market participants agree with the need, it would like comments on several questions:

- **What are the needs of market participants for long-term transmission rights in RTO markets?**
- **What has been the experience with congestion pricing and transmission rights of market participants in RTO markets?**
- **Have financial right allocations been sufficient to meet participants' needs for congestion hedging and long-term resource planning and acquisition?**

Because the Midwest ISO has operated for such a short period of time, it is impossible for the OMS to answer any of the above questions with hard factual data. However, the OMS points out that the FERC Staff has made an assumption at the outset that, at first added some confusion regarding answering its third question related to long-term resource planning and acquisition:

> "Most RTOs do provide long-term transmission rights (i.e., rights with terms greater than one year) for transmission upgrades or expansion that increase transmission capability. These long-term transmission expansion rights merit extensive discussion in

[5] FERC Staff Report at 4.

> themselves, but the paper will focus on long-term rights to existing transmission capacity."[6]

With respect to long-term financial rights associated with new infrastructure, the concern of some market participants is that, without such rights, it is difficult to finance new generation projects that are located remote from the load. Later in its discussion paper, the FERC Staff notes that the real issue may be not on a specific project, but rather on the "overall risk profile of the utility," and this may impair the utility's "overall financial flexibility and ability to make the strategic decision to invest in new generation (instead of, for example, to purchase power through a contract)."[7] The point here is that just having long-term financial rights for new generation options may not be sufficient to mitigate the perceived poor risk profile that a utility may have because of its congestion cost risk on existing generation resources. In part, this explains the emphasis that the FERC Staff has placed on long-term financial rights for existing transmission capacity as opposed to similar rights for transmission upgrades.

1. **To guarantee long-term transmission rights absent grid expansion means shifting the congestion costs among market participants without lowering that overall risk.**

Functional energy markets can encourage market participants to develop many risk management instruments, such as demand resource options. While there may be other methods for reducing the risk of congestion costs in the long-term, expanding transmission capacity appears to be the most direct means of decreasing that risk. Without increasing the capacity of the electrical system, moving to long-term transmission rights cannot in and of itself decrease the overall risk of congestion cost, and may only prove to move that risk from one set of market participants to another.

For new generation resources, implications for the ability to hedge congestion cost risk are directly related to the deliverability standards for DNRs that must be met in order for the RTO to grant a long-term FTR. Assuming a greater amount of transmission capacity is built to meet deliverability standards, the greater will be the assurance for market participants that they will be able to hedge their overall congestion costs over a longer period of time. Any realistic consideration of long-term transmission rights must take into consideration the relationship

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[6] Ibid, p.4.

[7] Ibid, p. 16.

between resource deliverability standards and the ability to hedge congestion costs on a long-term basis.

2. Implications for revenue adequacy of long-term financial transmission rights

The FERC Staff discussion paper relates the uncertainty with respect to revenue adequacy to fund FTRs to changes in the topology of the network along with unexpected loop flow; i.e., "events that were not in the model used to identify the feasible set of rights" that "can reduce congestion revenues collected below the level needed to pay existing FTR holders."[8] In this regard, the FERC Staff believes that "the probability of revenue insufficiency is likely to be greater with long-term financial rights"[9] and raised the following questions.

- **Should long-term financial rights be fully funded or subject to revenue shortfalls due to transmission network changes?**
- **How should potential revenue shortfalls be allocated?**
- **If long-term financial rights are awarded based on forecast grid conditions, but maintenance of the grid declines, resulting in future infeasibility, which parties should be responsible for maintaining the revenue adequacy of the rights?**

The primary concern here is, if the hedging value of long-term FTRs is decreased because of revenue inadequacy, does the RTO need to protect these particular FTRs from having to pay for a share of the revenue inadequacy or should they be equally subject to prorated FTR payments like everyone else? In this regard, it is important to point out that if longer-term transmission rights are not subject to prorating, then these rights should require a higher risk premium than shorter-term transmission rights that are subject to prorating. This is because the longer the term for which risks are to be mitigated, the greater the amount of uncertainty and the higher the cost of mitigating that risk. The OMS is not aware of any proposals or practical ways to set a higher risk premium on long-term transmission rights, and if such rights were granted without being subject to prorating or to a higher risk premium, this is likely to result in inequities among market participants. Providing some market participants with long-term transmission rights that failed to incorporate a risk premium that accurately reflected the potential long-term congestion costs or subjected some customers to greater likelihood of pro ration for otherwise equivalent service could be unduly preferential and discriminatory.

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[8] Ibid, p. 15.

[9] Ibid, p. 15.

As a practical matter, this is clearly a distributional question. When the RTO is short of revenues, someone must make up the shortfall (e.g., an uplift charge to all customers). If all load-serving entities are allowed the same opportunity to obtain long-term FTRs, then an expectation might be that each load-serving entity would have approximately the same pro rata share of long-term FTRs in their FTR portfolios. If RTO revenue shortfalls are allocated on the basis of a pro rata share of megawatts of FTRs held, then it should make no difference whether or not long-term FTRs were protected from an allocated share of a revenue shortfall because the amount of the shortfall taken from a load-serving entity would be approximately the same with or without long-term FTRs being protected. However, in practice the actual allocation of FTRs is likely to result in some load-serving entities having a higher mix of long-term FTRs than others. Thus, in order to avoid preferential treatment, there is no strong argument for exempting long-term FTRs from experiencing a pro rata share of revenue shortages.

B. Physical Rights as an Alternative for Providing Long-Term Transmission Rights

Reverting to OATT service is not equivalent to hedging congestion costs to a level equal to the cost of meeting load from owned generation. Specifically, in an OATT service context, load-serving entities will enter into short-term bilateral purchases and sales of power. This can occur on either a firm or non-firm basis. Short-term purchased power substitutes energy at a lower price than from owned generation, and short-term sales result in profits that are subtracted from the cost of meeting load from owned generation. These transactions require the load-serving entity to request physical transmission service, and, if available, the Transmission Provider grants such service, subject to possible curtailment through Transmission Line Loading Relief (TLR). The FERC Staff discussion paper correctly recognizes the fact that this first come - first served approach with possible TLRs is less efficient than having a bid system where the RTO uses security constrained economic dispatch to determine which generators will meet overall load at the least cost. Physical scheduling rights are not necessary, nor particularly desirable, as an alternative to financial rights. However, if some form of reverting to physical rights is used, it should not be allowed to reduce the efficiency of the RTO centralized dispatch.

IV. Conclusion

The OMS is not unalterably opposed to longer-term transmission rights, if they can be designed in such a manner as to fairly apportion the risks so as to avoid undue discrimination and not disrupt the real-time market dispatch. However, the OMS is concerned that, if they are pursued, long-term transmission rights be designed in a way that avoids providing some market participants with unduly preferential services. Without adequate expansion of grid capacity, long-term transmission rights are likely to only redistribute congestion costs among market participants.

The OMS recognizes that long-term financial transmission rights could provide added incentive to build infrastructure to expand the electrical system so as to reduce congestion costs in the long term. However, a properly executed regional planning process, including siting with appropriate cost allocation for reliability and regionally beneficial upgrades to the transmission system, is likely to be a more important factor in reducing congestion costs in the long term.

Midwest Stand-Alone Transmission Companies

Presentation to

Organization of Midwest States

Board of Directors Meeting

June 22, 2005

Disclaimer: This presentation is based upon a training session given by the Midwest Stand-Alone Transmission Companies (MSATs) to staff at the Federal Energy Regulatory Commission (FERC) in February 2005. The views expressed in the presentation are not intended to be construed as official statements of position by any MSAT on any issue discussed. Each MSAT expressly reserves the right to take individual positions on the issues discussed herein in any proceeding before the FERC or in any other context. Please note that GridAmerica announced its plans to cease operations effective November 1, 2005 and will continue as a member of the MSATs through August 31, 2005.

Overview

PART I – Introduction

- Who are We?
- What are SATCs About?
- Why is Transmission Important?
- Impact of Transmission on the Retail Bill

PART II – Investing in Transmission

- The Planning Process
- Financing Capital Projects
- Factors Influencing Investment Decisions
- The Need for a New Investment Paradigm

Overview (cont.)

PART III –Fallacies of Electric Restructuring

PART IV – Translation into Policy

- Policies that Encourage Plant Investment
- Encouraging the Formation of SATCs
- Business Structure Recognition
- Safeguarding Transmission Revenue
- Transmission Planning and Investment
- Reliability
- Energy Market Issues

PART V – Questions and Answers

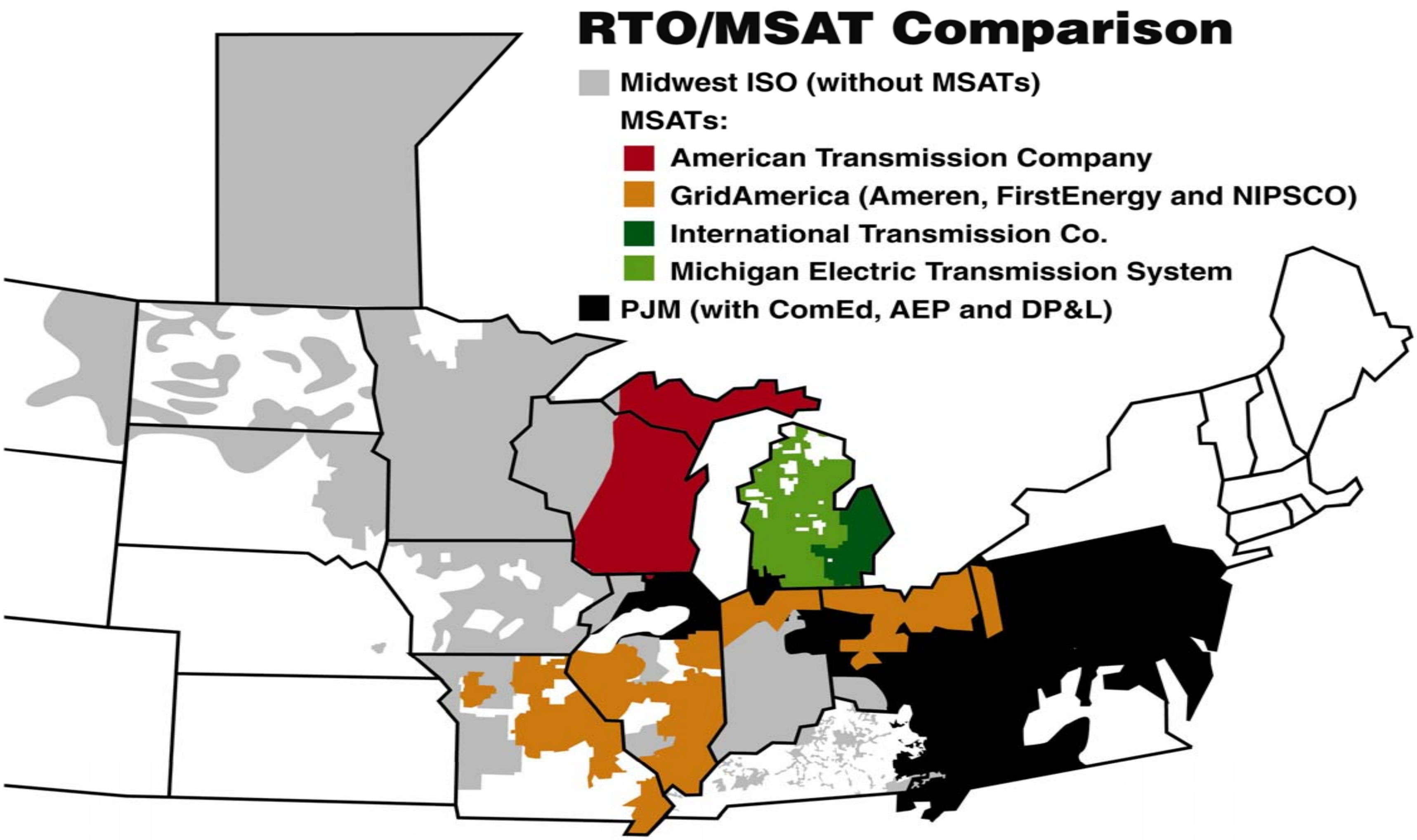
Appendix

PART I

Introduction

Who are We?

Location

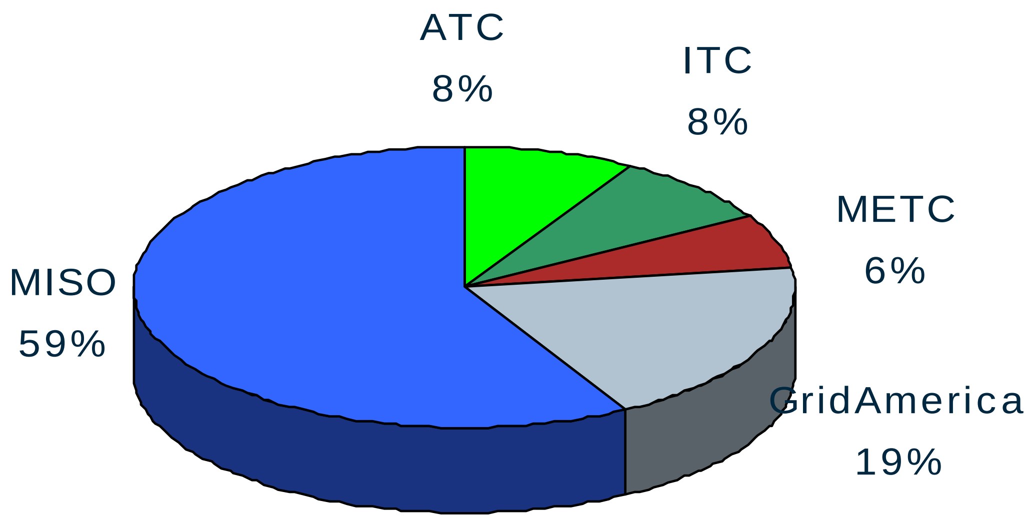

RTO/MSAT Comparison
Midwest ISO (without MSATs)
MSATs:
American Transmission Company
GridAmerica (Ameren, FirstEnergy and NIPSCO)
International Transmission Co.
Michigan Electric Transmission System
PJM (with ComEd, AEP and DP&L)

Fact Sheet (best available rounded data)

	Gross Plant	Transmission	Peak Demand
American Transmission Company — The Energy Access Company	$1,500 million	8,900 miles	11,600 MW
GridAmerica	$2,200 million	15,000 miles	28,000 MW
ITC International Transmission Company	$900 million	2,700 miles	11,600 MW
METC Michigan Electric Transmission Company, LLC — A Trans-Elect Enterprise	$500 million	5,400 miles	8,300 MW
Totals:	***$5,100 million***	***32,000 miles***	***59,500 MW***

MSAT Demand Relative to the Midwest ISO

Demand **MSAT Total 41%**



What Are SATCs About?

Business Interests

Exclusive Focus on Transmission

- our business is investing in, planning, owning, and/or managing transmission
- RTO retains functional/operational control

MSATs are NOT Market Participants or Vertically-Integrated Utilities (VIUs)

- do not own or operate generation
- do not serve retail load in the Midwest ISO
- do not buy or sell energy in the Midwest ISO

Recognized Benefits of For-Profit SATC Business Structures

- improved asset management
- enhanced access to capital
- service innovation (technologies / performance-based rates)
- greater independence

For-Profit / Stand-Alone Attributes

“We have long recognized that the ITC business model can bring significant benefits to the industry. Their for-profit nature with a focus on the transmission business is ideally suited to bring about: (1) improved asset management including increased investment, (2) improved access to capital markets given a more focused business model than vertically-integrated utilities, (3) development of innovative services, and (4) additional independence from market participants. For example, under the hybrid RTO model approved today an ITC may file revenue requirements and incentive rate mechanisms under section 205 after collaboration with the RTO, thus ensuring rate recovery including risk-based return on investment. ITCs may control outages and provide input (e.g., near-term facility ratings) into the calculation of available transmission capability, thus allowing the ITC to earn risk-based rewards for efficient performance.” *Alliance Companies,* 99 FERC ¶ 61,105 at p. 61,430 (2002).

“We also believe that accelerated development of independent stand-alone transmission businesses will lead to an accelerated transition to competitive, regional bulk power markets and is in the best interests of consumers” *International Transmission Company*, 92 FERC ¶ 61,276 at p. 61,917 (2000).

“[B]y creating an independent stand-alone transmission company from a vertically integrated utility, the proposed transaction furthers the Commission’s open access and RTO initiatives, accelerates the transition to competitive regional bulk power markets, and will result in significant benefits to . . . transmission customers.” *Trans-Elect, Inc.*, *et al.*, 98 FERC ¶ 61,368 at p. 62,590 (2002).

“We have long recognized that the Independent Transmission Company (ITC) business model can bring significant benefits to the industry. Their for-profit nature with a focus on the transmission business is ideally suited to bring about: (1) improved asset management including increased investment; (2) improved access to capital markets given a more focused business model than that of vertically integrated utilities; (3) development of innovative services; and (4) additional independence from market participants. We believe that these characteristics of ITCs can have significant benefits for the implementation of Standard Market Design, particularly in the areas of development of transmission infrastructure and structural independence from market participants.” *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, Prop. FERC Stats. & Regs. ¶ 32,563 at P 132 (2002).

Relationship with Regulatory Agencies

- All of the MSATs are For-Profit Companies
  - — seek return for investors
  - — similar to Investor Owned Utilities
  - — different from RTOs and ISOs (which are non-profit entities)
- SATCs are FERC-Regulated Electric Utilities
  - — revenue requirements*
  - — resulting rates*
- SATCs are NOT Service-Regulated by the States
  - — exception: transmission siting

* Some differences among SATCs (*e.g.* GridAmerica does not have separate revenue requirements or resulting rates approved by FERC).

Why is Transmission Important?

Why is Transmission Important?

Reliability Function

- increase access to reserves
- plan for future reliability needs
- reduce outages, fewer momentaries, etc.

Market Enabler

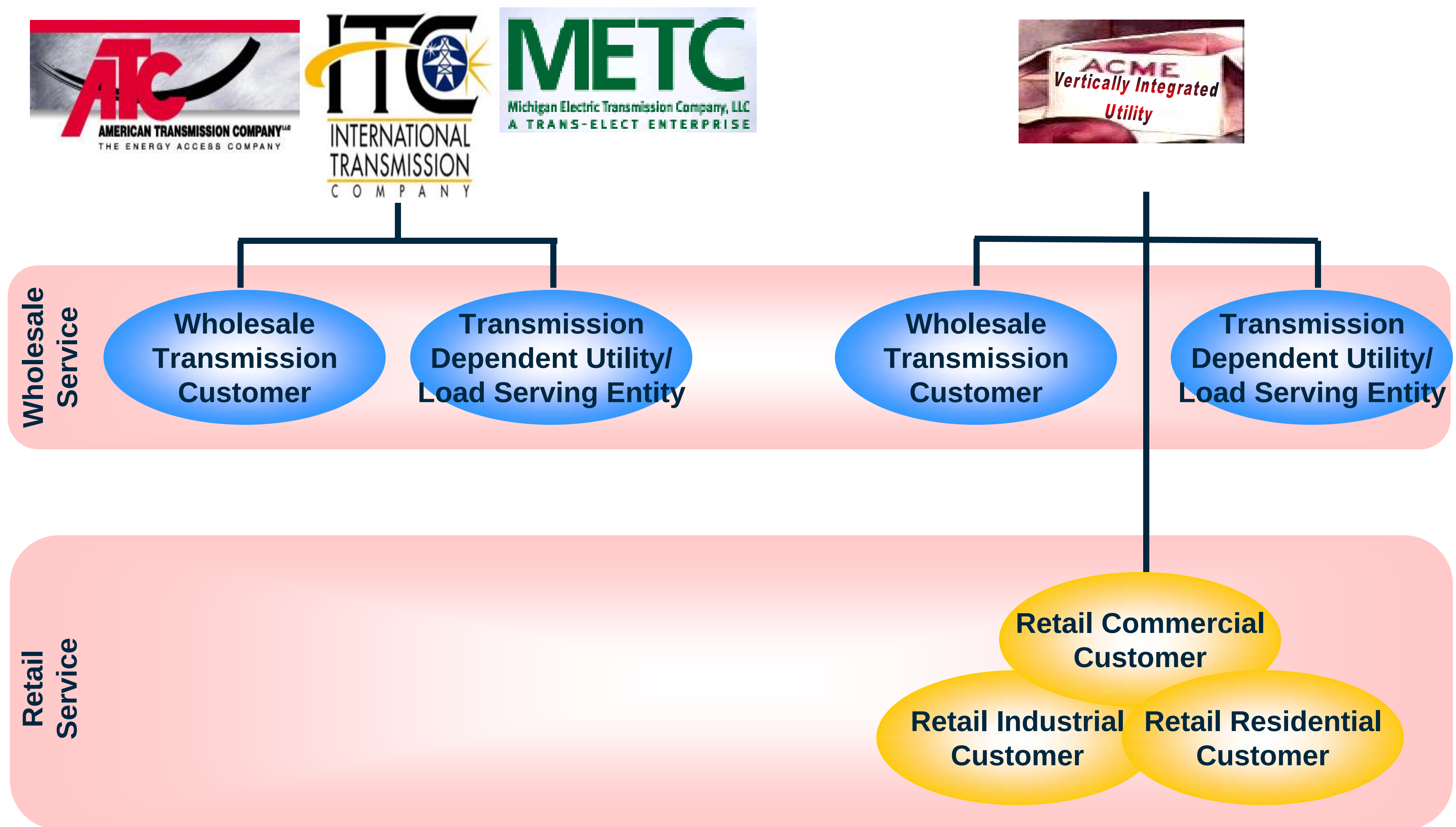
- connect generation to load
- reduce congestion
- prevent the exercise of market power

Our Role

- operations
- SATC finance
- new investment

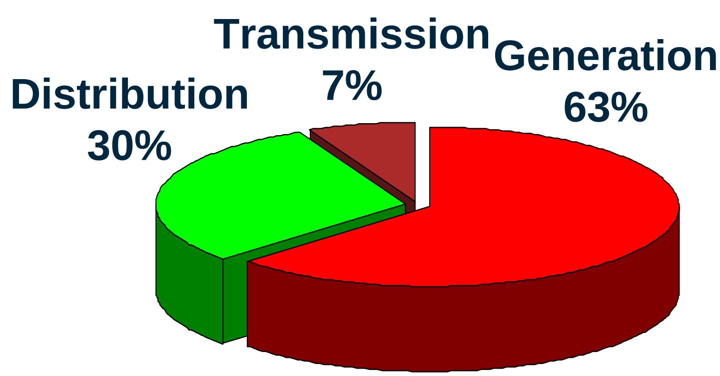
Impact of Transmission on the Retail Bill

Distinguishing Between Wholesale & Retail Customers



Transmission Component of Retail Bill

- Transmission is only a small component of total delivered electricity cost:



Source: EIA Annual Energy Outlook 2003

PART II

Investing in Transmission

Transmission Planning Process

Transmission Planning

- Responsibilities
  - — SATC – within footprint
  - — RTO – regional coordination
  - — Midwest ISO Transmission Expansion Plan (MTEP)
  - — Regional Expansion Criteria and Benefits (RECB)
- Regulatory Oversight
  - — state agencies – siting authority
  - — FERC – cost allocation (including interregional) and related compensation
  - — legislation – greater federal involvement in siting

Financing Capital Projects

Transmission Investor Profile

- Historically
  - — Investor Owned Utilities
  - — Municipalities
  - — Cooperatives
  - — State and Federal Agencies
- SATCs – Emerging and Still-Evolving Investment Structures
  - — ATCLLC – owned by customers / entities divesting transmission assets
  - — GridAmerica – manager of assets owned by members (Ameren, FirstEnergy, NIPSCO)
  - — International Transmission – owned by investors
  - — METC – owned by investors

Paying for New Facilities

- Transmission Service Rates
  - designed to recover costs plus reasonable return on investment
  - formula rates v. stated rates
- Project Financing
  - smaller projects – retained earnings may be sufficient
  - larger projects – debt or other third-party financing may be required
  - VIUs – may use revenue from vertically-integrated operations
- Section 204 of the Federal Power Act
  - applicable to jurisdictional utilities
  - requires a utility to make a filing before certain security issuances or borrowings

The Need for a New Investment Paradigm

Competition for Capital

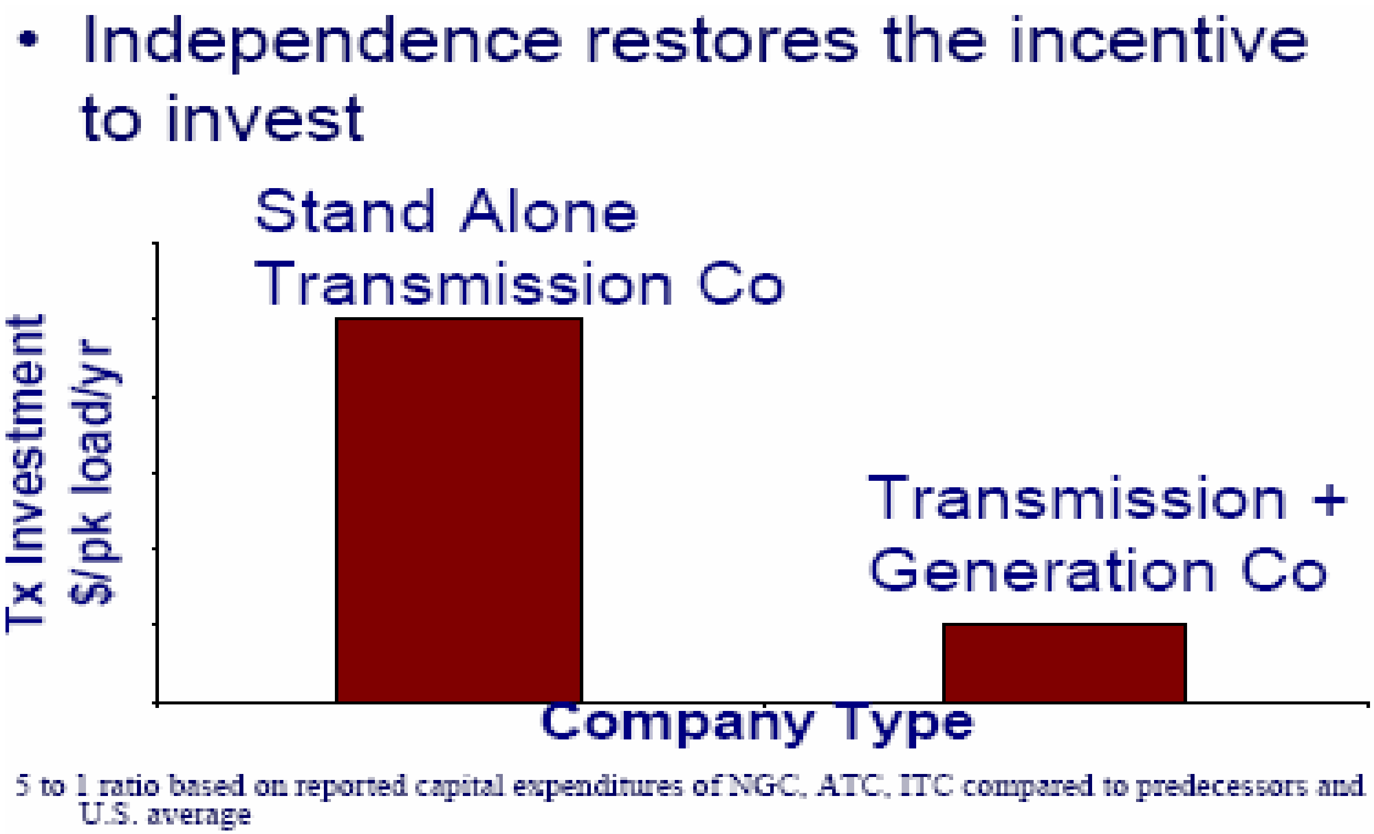
VIUs

- Internal Competition for Capital
  - — need to upgrade distribution facilities
  - — need to add generation
  - — “unregulated” merchant considerations
  - — need to augment transmission
- Invest Less in Transmission (next slides)

SATCs

- No Internal Competition for Capital
  - — exclusive focus on transmission
- Invest More in Transmission (next slides)
- Constraints Against Overbuilding
  - state need requirements
  - stakeholder input

SATC Investment in Transmission



Source: Unlocking Transmission Investment, Presentation by Chairman Wood, (January 28, 2004).

Planned Transmission Investment of SATCs and VITOs

		2004-2008		(millions of dollars)				
	Net Plant	Investment	===============Capital Expenditures ====================					
	12/31/2003	% NBV	2004	2005	2006	2007	2008	Total
ATC	$ 771	193%	$ 270	$ 286	$ 322	$ 309	$ 304	$ 1,491
ITC	$ 387	127%	$ 85	$ 105	$ 100	$ 100	$ 100	$ 490
METC	$ 277	78%	$ 28	$ 42	$ 57	$ 45	$ 44	$ 215
SATCs:	$ 1,435	**153%**	$ 383	$ 433	$ 479	$ 454	$ 448	$ 2,196
VITOs:	$ 38,762	61%	$ 3,798	$ 4,688	$ 4,926	$ 5,095	$ 5,110	$ 23,617
Ameren & FE	$ 2,119	35%	$ 60	$ 156	$ 219	$ 170	$ 132	$ 737
Rev VITOs:	$ 40,881	**60%**	$ 3,858	$ 4,844	$ 5,145	$ 5,265	$ 5,242	$ 24,354

Note: Ameren and FirstEnergy were taken out of the SATC numbers and added to the vertically-integrated numbers

Source EEI

SATC Investment in Transmission

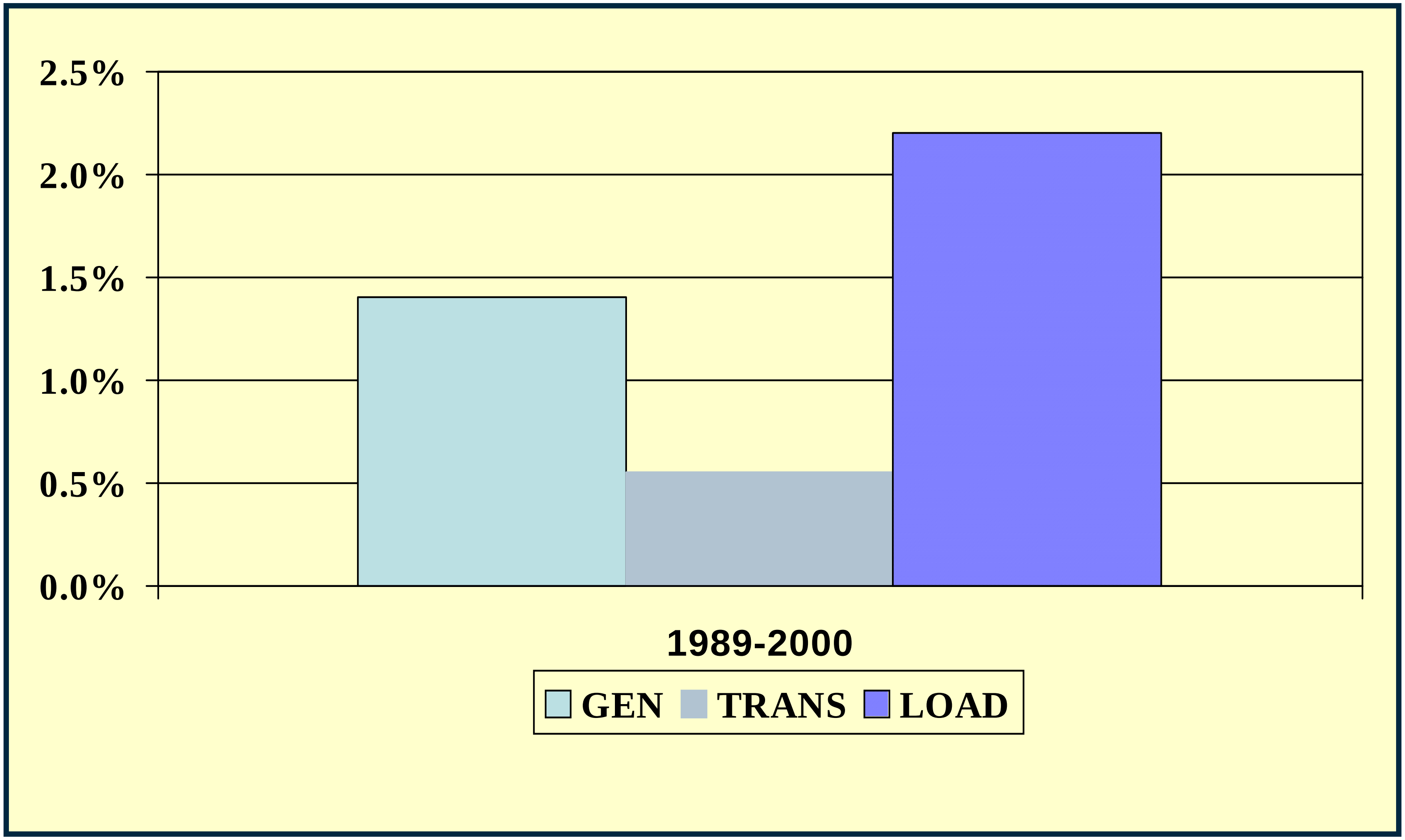
“The independent transmission companies . . . have demonstrated . . . a pretty extraordinary commitment to investment that we have not seen on the incumbent side.”

Commissioner Brownell, *Market-Based Rates for Public Utilities*, Docket No. RM04-7-000, technical conference convened on December 7, 2004 (Tr. at 162).

“[T]he interesting issue with the independent transmission companies is they [are] more than anxious to build their rate base with new transmission investments that doesn’t seem to carry over to the vertically integrated utility.”

Richard O’Neill, Office of Markets, Tariffs, and Rates, *Market-Based Rates for Public Utilities*, Docket No. RM04-7-000, technical conference convened on December 7, 2004 (Tr. at 71).

Annual Growth Rates in Gen, Trans, Load



Source: Chairman Wood presentation at NARUC Annual Meeting (November 17, 2004).

Decline in Transmission Investment

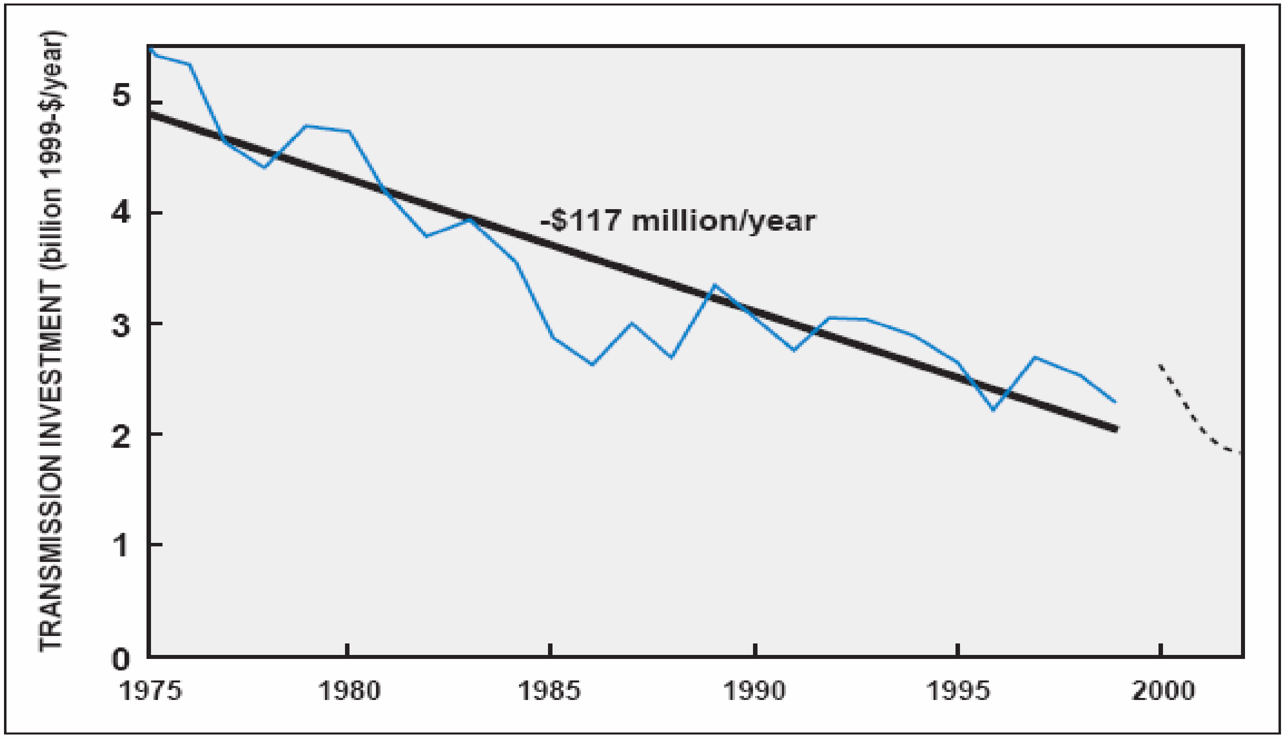


Fig. 1.4 Transmission System Investment over Time

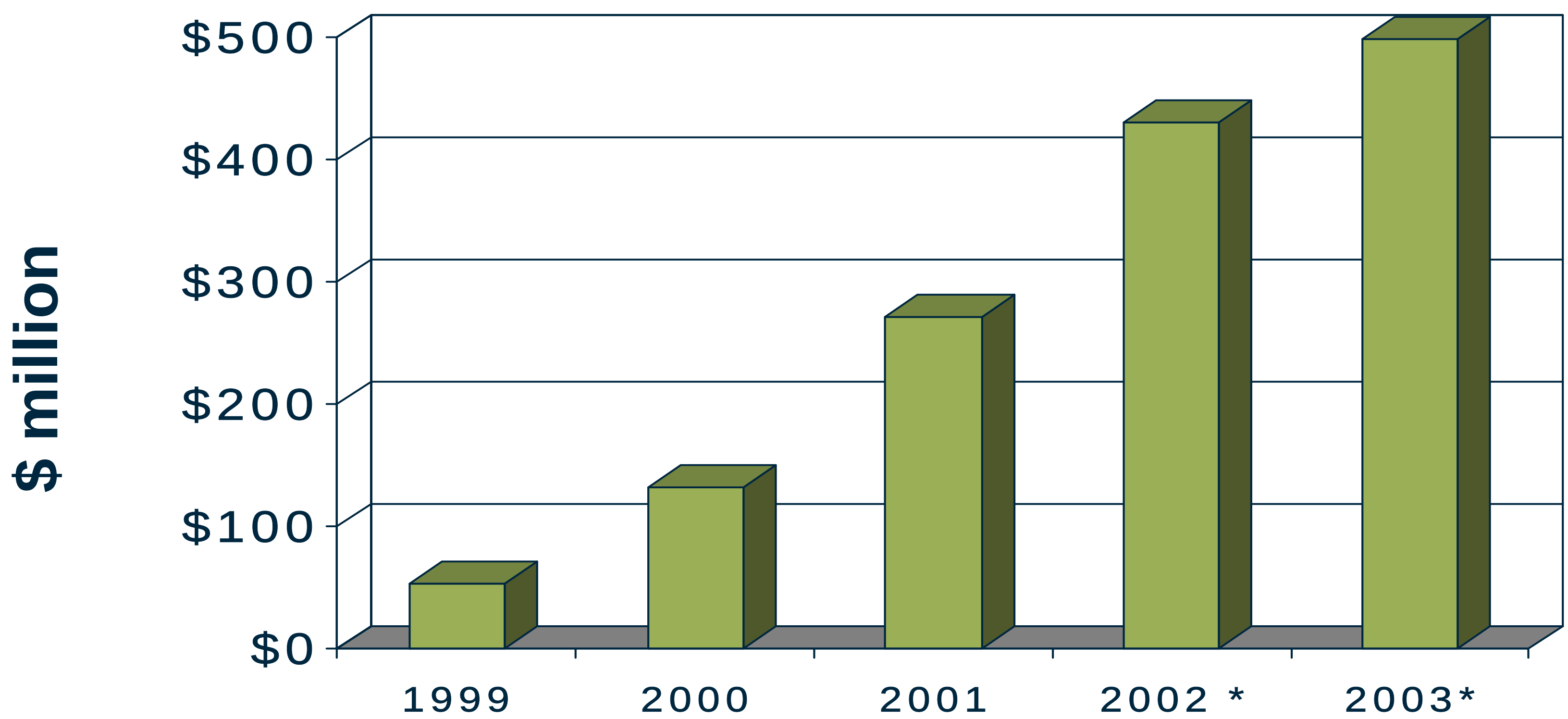
Investment in new transmission facilities has declined steadily for the last 25 years.

Source: E. Hirst and B. Kirby. 2001. *Transmission Planning for a Restructured U.S. Electricity Industry.* Edison Electric Institute.

US Since 1998: $1 - $3 million/GW peak load annually

Compare to UK Since 1996: **$10 million/GW peak load annually**

Increase in Congestion Costs (PJM example)



Source: Derived from data presented in PJM "State of the Market Report" for year 2003 (Table 6-1) (available at <http://www.pjm.com/markets/market-monitor/som.html>).

*** Includes PJM West**

PART III

Fallacies of Electric Restructuring

Fallacy #1

Fallacy:

- Locational marginal pricing (LMP) will solve transmission investment problems.

Reality:

- transmission is not a short-term marginal cost good
- high LMPs (by themselves) have not resulted in transmission solutions
- LMP is a blunt diagnostic tool to indicate if and where transmission is needed
- LMPs may actually discourage new investment if potential investors benefit from the existence of congestion
  - *e.g.*, holders of Firm Transmission Rights (FTRs) would see the value of those rights diminished if congestion is eliminated
- some investors (SATCs) are not structured to hold FTRs
  - the award of FTRs as a hedge against congestion is not an incentive
  - holding FTRs may trigger “market participant” obligations

Fallacy #2

Fallacy:

- Participant funding matches costs with benefits and encourages transmission investment.

Reality:

- use of participant funding has <u>not</u> increased transmission investment
- “free rider” problem
- disputes arise and result in project delays and cancellations
  - classification of new facilities (interconnection v. network upgrades)
  - allocation of facility costs
- greater recognition that transmission creates public benefits as highways promote commerce (support allocation of costs into existing rates and/or on a regional basis)

Fallacy #3

Fallacy:

- Market-based transmission solutions (“merchant transmission”) will solve the nation’s infrastructure needs.

Reality:

- the Eastern Interconnection is a synchronous machine
- difficult to allocate property rights on a line-specific basis
- merchant transmission proposals have to date been largely unsuccessful
- may be niche for merchant transmission (particularly DC projects)

Fallacy #4

Fallacy:

- Generation investment is a perfect substitute for new transmission.

Reality:

- generation investment decisions turn on different considerations
- generation is governed by different set of market monitoring rules, protocols and procedures
- generation is subject to potential manipulation
- transmission has a higher rate of availability than generation

PART IV

Translation into Policy

Fundamental MSAT Policy Positions

Introduction

Disclaimer

- Intent – Show Nexus Between Regulatory Policies and Real World
- Individual MSATs May Have Their Own Views

Overview

- Business Structure Recognition
- Protection of Transmission Revenue
- Transmission Planning and Investment
- Reliability
- Energy Market Issues

Policies that Encourage Plant Investment (Examples)

- Increased Rates of Return on Equity
- Accelerated (Book) Depreciation
- Current Return on Construction Work in Progress (CWIP)
- Current Expense Treatment of Pre-Certification Costs
- Incentive Rate of Return Structures
- Formula Rates
- Performance-Based Rates (PBRs)
- Structural / Institutional Alternatives (*e.g.*, formation of SATCs)

Encouraging the Formation of SATCs

Legislation

- Spring 2005 Energy Bills
- state legislation (*e.g.* Wisconsin Act 9)
- Eminent domain clarification

Incentives

- increased rates of return on equity
- other ratemaking approaches appropriate to specific needs (*e.g.* ATC treatment of new investments)

Identification and Mitigation of Vertical Market Power

- market-based rate restrictions
- merger approval

Greater Functionality

- delegation of more functions to ITCs
- open-minded to new proposals designed to enhance efficiency, optimize assets, etc.
- recognition of new business plans and operational structures

No “One-Size-Fits-All” Policies

Business Structure Recognition

- Why these issues are important to us:
  - — the SATC model is a still-emerging business structure
  - — not structured to perform the same functions as VIUs
  - — different cost and revenue dynamics, organizational and ownership structures, etc.
- Translation into Policy:
  - — oppose polices that require SATCs to perform “market participant” functions against their will
  - — terminology should be used accurately
  - — policies should be flexible enough to accommodate various transmission ownership structures

Creditworthiness and Rate Filing Issues

- Why these issues are important to us:
  - transmission is our only source of revenue (no diversification)
- Translation into Policy
  - Tariff Filing Rights
  - Liability and Indemnification Protections
  - Credit and Collateral Standards
  - Bankruptcy Policies
  - Billing and Accounting Practices
  - Order of Revenue Crediting

Transmission Planning and Investment

- Why these issues are important to us:
  - — transmission ownership and management is our only business
  - — have a direct interest in how transmission projects are planned
- Translation into Policy
  - — generally support “bottom up” planning within the RTO
  - — support effort to better coordinate regional projects (*e.g.*, MISO/PJM Cross-Border Projects under Joint Operating Agreement)
  - — support polices that permit effective management of investment risks and rewards
  - — distinguish the role of “merchant transmission” projects
  - — question the ability of LMP and “participant funding” to incent transmission expansion

Reliability

- Why these issues are important to us:
  - — impact of August 14, 2003 blackout
  - — need for new infrastructure (modernization of the grid)
  - — protect our investments
- Translation into Policy
  - — support mandatory reliability standards and creation of reliability organization
  - — support standardization of reactive power procurement practices
  - — support reasonable liability protections

Energy Market Issues

- Why these issues are important to us:
  - — we are not market participants
  - — transmission is a “market enabler”
  - — market design influences transmission investment and operations
- Translation into Policy
  - — new infrastructure is often required to resolve congestion problems
  - — market policies should seek to identify infrastructure needs
  - — the ability of LMP and FTR market design features to guide investment decisions should not be overestimated
  - — market features should not have unintended consequences
  - — support structural solutions to vertical market power (*e.g.* formation of SATCs)

PART V

Questions & Answers

APPENDIX

Further Information About the MSATs and their Business Structure

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Corporate Structures

- ATCLLC
  - — owner and operator of divested transmission assets
  - — owned at corporate level by customers
  - — has five control areas within its footprint
  - — operates as a “Transmission Owner” within the Midwest ISO (Midwest ISO Agreement)
- GridAmerica
  - — manages transmission assets owned by its members (Ameren, FirstEnergy, NIPSCO)
  - — operates as an “Independent Transmission Company” (Appendix I) within the Midwest ISO
- International Transmission
  - — owner and operator of divested transmission assets purchased by private investors
  - — joint control area operator (with METC)
  - — operates as an “Independent Transmission Company” (Appendix I) within the Midwest ISO
- METC
  - — owner and operator of divested transmission assets purchased by private investors
  - — joint control area operator (with International Transmission)
  - — operates as a “Transmission Owner” within the Midwest ISO (Midwest ISO Agreement)

Commonly Used Terms (Simplified Definitions)

- Transmission Owner - owns transmission facilities; in the Midwest ISO, may be a “Transmission Owner” (signatory to Midwest ISO Agreement) or “Independent Transmission Company” (signatory to Appendix I Agreement)
- Transmission Provider – provides service over transmission facilities pursuant to an open access transmission tariff (OATT)
- Control Area – portion of grid defined by physical operations (generation, transmission, and loads within a metered boundary) within which a common control scheme applies; more than 35 within the Midwest ISO
- Pricing Zone – portion of grid defined for ratemaking purposes within which a common transmission rate is charged; more than 25 within the Midwest ISO
- Transmission Customer – typically purchases transmission service under the OATT
- Market Participant – having a financial interest in the buying or selling of energy in relevant markets, participating in energy markets, providing ancillary services, or engaging in similar activities
- Load-Serving Entity – secures energy and transmission to serve end-users
- Distribution – connects transmission system to end-use customers
- Generation – supplies energy into transmission system

Commonly Used Terms (Application to MSATs)

	ATCLLC	GridAmerica	International Transmission	METC
Transmission Owner MISO Status	YES MISO Agreement	NO (manages facilities) Appendix I (ITC)	YES Appendix I (ITC)	YES MISO Agreement
Transmission Provider	NO (Midwest ISO = Transmission Provider)			
Control Area Operator	NO (divesting companies)	NO (member companies)	YES (operate joint control area)	
Pricing Zone	Single Zone (after transition from 5)	Three Zones (one for each member)	Single Zone	Joint Zone (MPPA / Wolverine)
Market Participant	NO	NO	NO	NO
Load-Serving Entity	NO	NO	NO	NO
Distribution Owner/Operator	NO	NO	NO	NO
Generation Owner/Operator	NO	NO	NO	NO

Highlights of Midwest ISO: 2004 State of the Market Report and Day-2 Energy Markets

Prepared by:

David B. Patton, Ph.D.

Independent Market Monitor
Midwest ISO

June 22, 2005

POTOMAC ECONOMICS

Introduction – 2004 State of the Market Report

- The Midwest ISO currently provides transmission service and is the reliability coordinator for the region.
- Operation of centralized day-ahead and real-time energy markets began April 1, 2005 (“Day 2 markets”).
- During 2004, our monitoring was primarily focused on transmission service and operations and the bilateral market outcomes.
- The areas addressed in the 2004 State of the Market Report include:
  - ✓ Characteristics of the Midwest Supply and Demand;
  - ✓ Wholesale Market Prices;
  - ✓ Transmission Service;
  - ✓ Transmission Operations; and
  - ✓ Network Integration Service Designations.

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Wholesale Electricity Prices

- The following figure shows price trends in the bilateral electricity markets during 2004.
- The prices shown are prices associated with day-ahead forward contracts for delivery at the Cinergy Hub, the most actively traded point on the Midwest ISO system.
- The figure shows monthly averages for both peak and off-peak periods and includes natural gas and coal price indices to indicate general trends in underlying input prices.
- This figure shows that prices were substantially higher during peak hours as expected and that prices were moderate during the summer.
  - ✓ Mild weather during the summer produced relatively low peak load conditions;
  - ✓ Declining natural gas prices also contributed to lower peak prices. Natural gas resources are frequently on the margin during peak hours and generally are not in off-peak hours.

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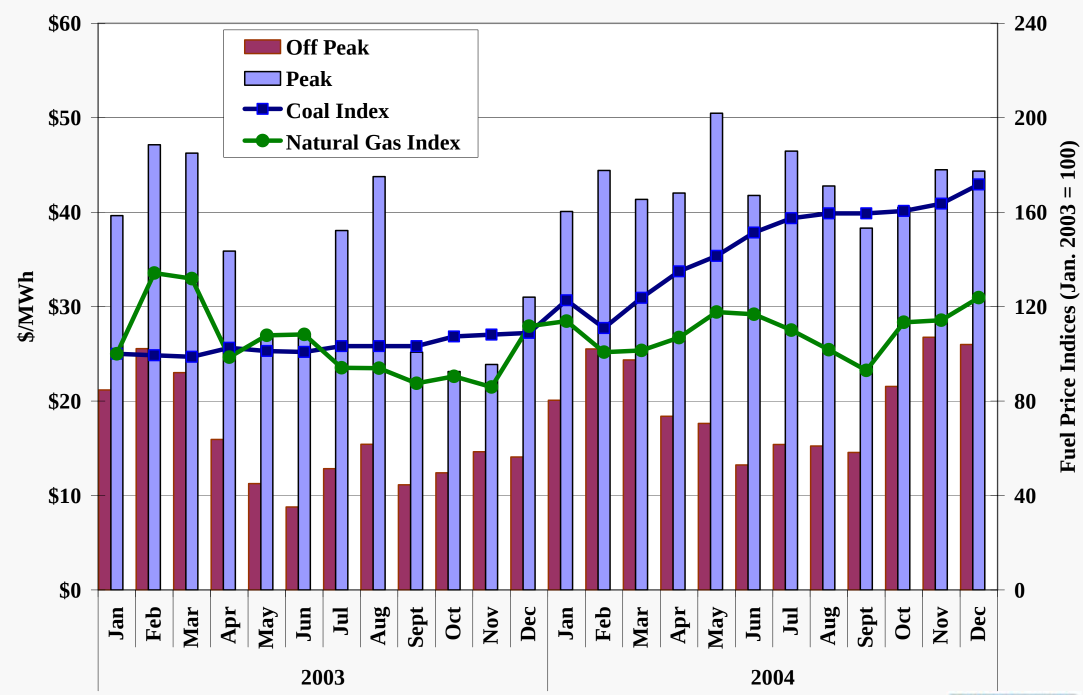
Monthly Average Electricity and Fuel Prices
Cinergy Day-Ahead Electricity Prices



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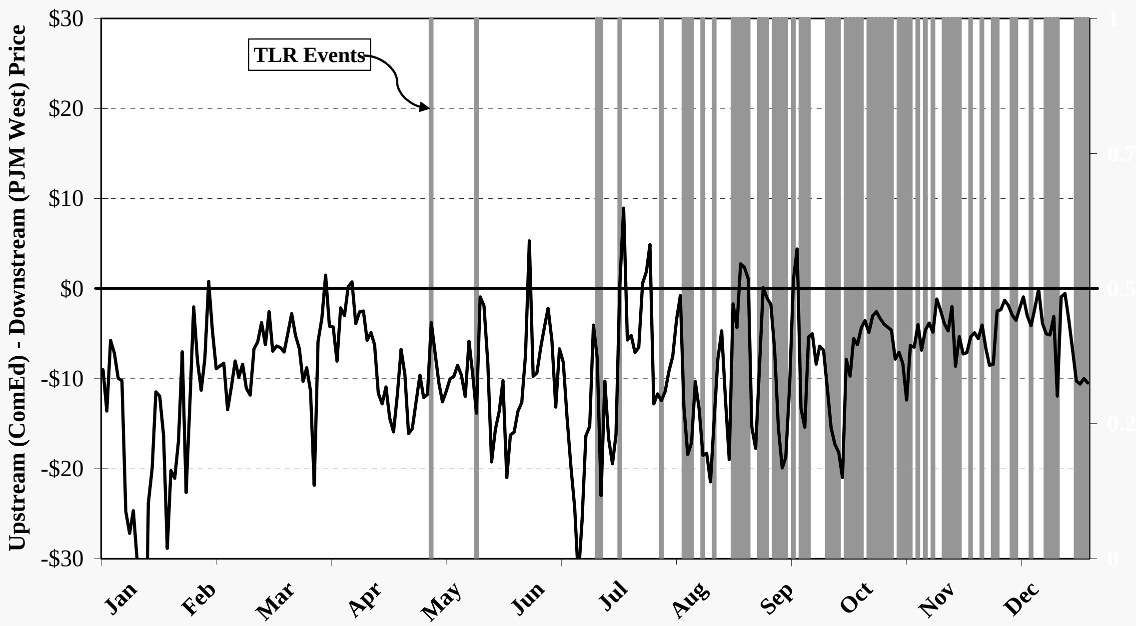
PJM Expansion and Transmission Constraints

- One of the most significant changes in the Midwest during 2004 was the integration into PJM of Commonwealth Edison in the May and AEP in the October of 2004.
  - ✓ Prior to the integration of AEP, transfers from ComEd to PJM were limited to 500 MW.
  - ✓ After the integration of AEP, PJM could economically dispatch the path from ComEd to PJM, utilizing a market to non-market process to reduce its flow when necessary over “coordinated” flowgates.
  - ✓ TLRs are called on the constrained facility to cause PJM to redispatch and curtail other non-firm transactions.
- When constraints are binding that limit flows across an interface, prices “downstream” of the constraint should rise relative to prices “upstream”.

PJM Expansion and Transmission Constraints

- The following analysis shows the relationship of bilateral prices between PJM West (downstream) and ComEd (upstream) during 2004, along with the TLRs called on selected NIPSCO flowgates in Northern ECAR.
- The integration of AEP that allowed full redispatch of the expanded PJM area initially cased serious overloads on the NIPSCO system, which was resolved by designating these as “coordinated” flowgates.
- The figure shows:
  - ✓ Consistent with market to non-market process, Midwest ISO called a large quantity of TLRs on the NIPSCO flowgates, which resulted in transaction curtailments and redispatch by PJM.
  - ✓ These TLRs resulted in a significant increase in curtailment of non-firm transactions by other participants over these west-to-east paths in ECAR.
  - ✓ Price convergence between Commonwealth Edison and PJM West improved, particularly in late 2004 when AEP was integrated.

Upstream-Downstream Prices and TLR Events
Selected NIPSCO Flowgates



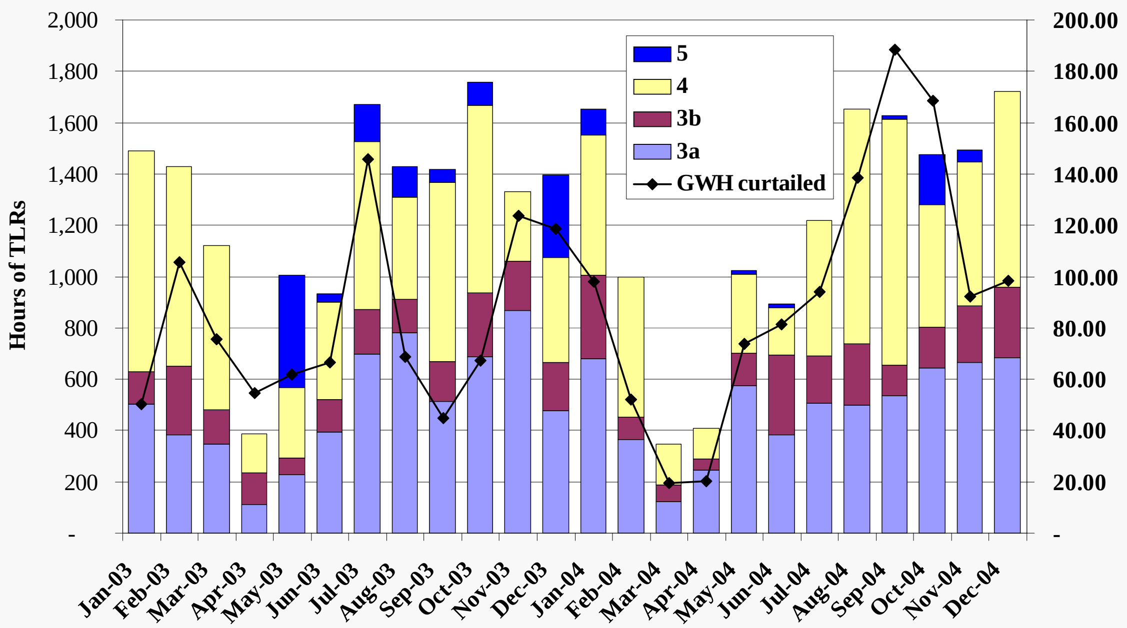
POTOMAC ECONOMICS

TLR Events and Curtailments in 2003

- The next figure shows the TLRs and associated curtailments in 2003 and 2004.
- The TLR levels include:
  - ✓ Level 3 – non-firm curtailments.
  - ✓ Level 4 – commitment or redispatch of specific resources or other operating procedures to manage specific constraints.
  - ✓ Level 5 – curtailment of firm transactions.
- The TLRs called on Midwest ISO flowgates (level 3 and above) account for about 60 percent of all TLRs called in the eastern interconnect.
- The figure shows that the TLR quantities between 2003 and 2004 are comparable.
  - ✓ Level 5 TLRs were higher in 2003 due to outages in North WUMS.
- Transaction curtailments increased substantially in the fall of 2004 due to the increased flows and TLRs associated with ComEd and AEP integration into PJM as described above.
- The annual report shows that the TLR process is inefficient and led to under-utilization of the transmission capability in the Midwest.

POTOMAC ECONOMICS

TLR Events and Transactions Curtailed 2003 to 2004



POTOMAC ECONOMICS

Conclusions: Day 1 vs. Day 2 Markets

- The transmission reservation process and the TLR process has been implemented competently by the ISO.
- However, our analysis indicates that these processes are substantially inferior to the Day 2 markets for managing congestion, utilizing available transmission capability, and maintaining reliability.
  - ✓ The Day 2 markets will dispatch the most effective resources to manage congestion.
  - ✓ Prices will more fully reflect the congestion and losses under the Day 2 markets, sending more accurate short-run and long-run economic signals.
  - ✓ The real-time economic redispatch (every 5 minutes) will allows transmission interfaces to be operated closer to the rated limits (e.g., to have lower transmission reservation margins and other operating offsets).
  - ✓ The relief available from redispatch is much more predictable and timely than relief through TLR or emergency redispatch, which should contribute to improved reliability.

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Initial Results of Midwest ISO Energy Markets

POTOMAC ECONOMICS

Midwest ISO Energy Prices

- The following figures show the prices at three locations in the real-time and day-ahead markets.
- The most significant congestion continues to be related to imports into WUMS.
  - ✓ This congestion can be seen in both the day-ahead and real-time figures when the WUMS prices substantially exceed prices in Minnesota.
- The figures show that prices increased substantially in early June:
  - ✓ This increase was driven primarily by the sizable increase load during this timeframe.
  - ✓ The increase in loads is due to the hot weather throughout the Midwest beginning on June 7.
  - ✓ Expiration of the cost-based offer requirement was not a major factor.
- Real-time prices are much more volatile than day-ahead prices as expected although the overall convergence between the markets has remained good.

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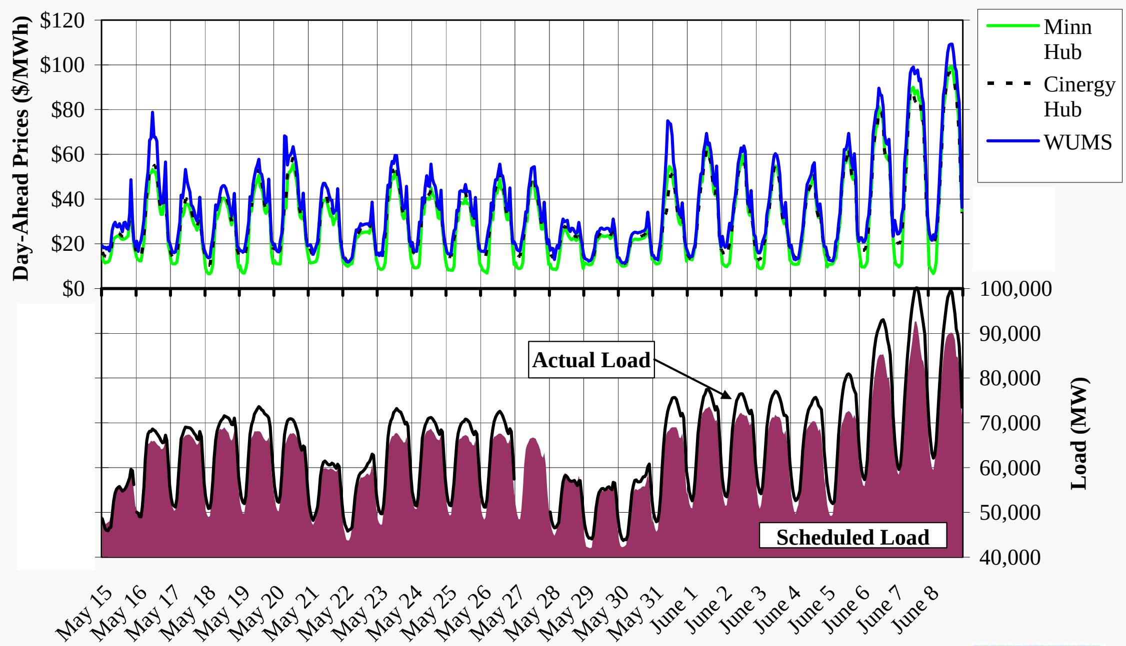
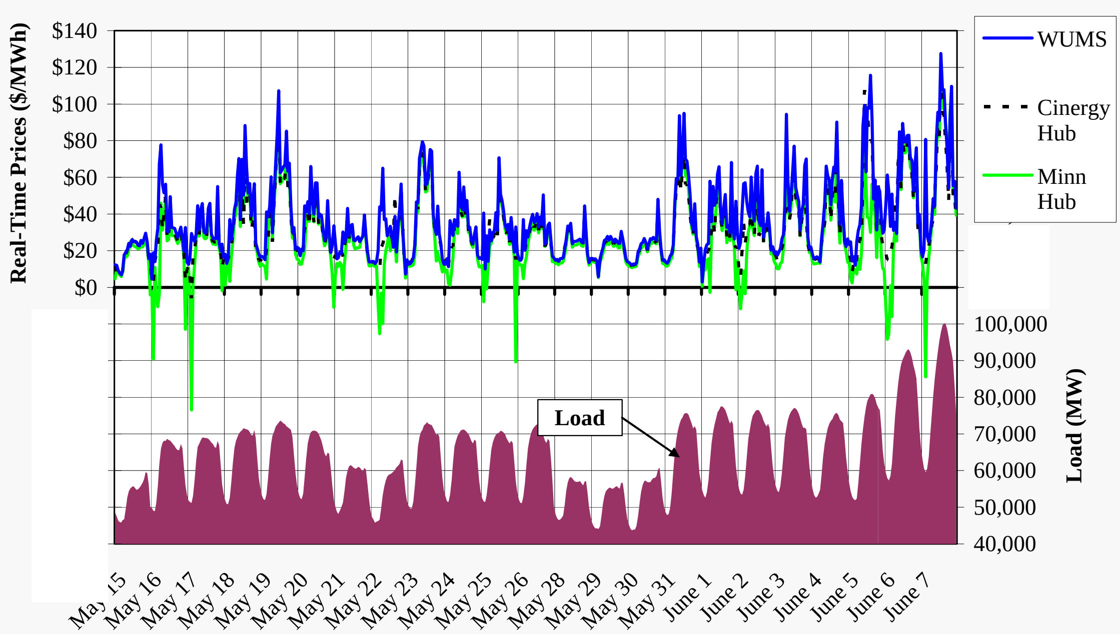
Day-Ahead Midwest ISO Energy Prices
May 15 to June 8, 2005



POTOMAC ECONOMICS

Real-Time Midwest ISO Energy Prices
May 15 to June 7, 2005



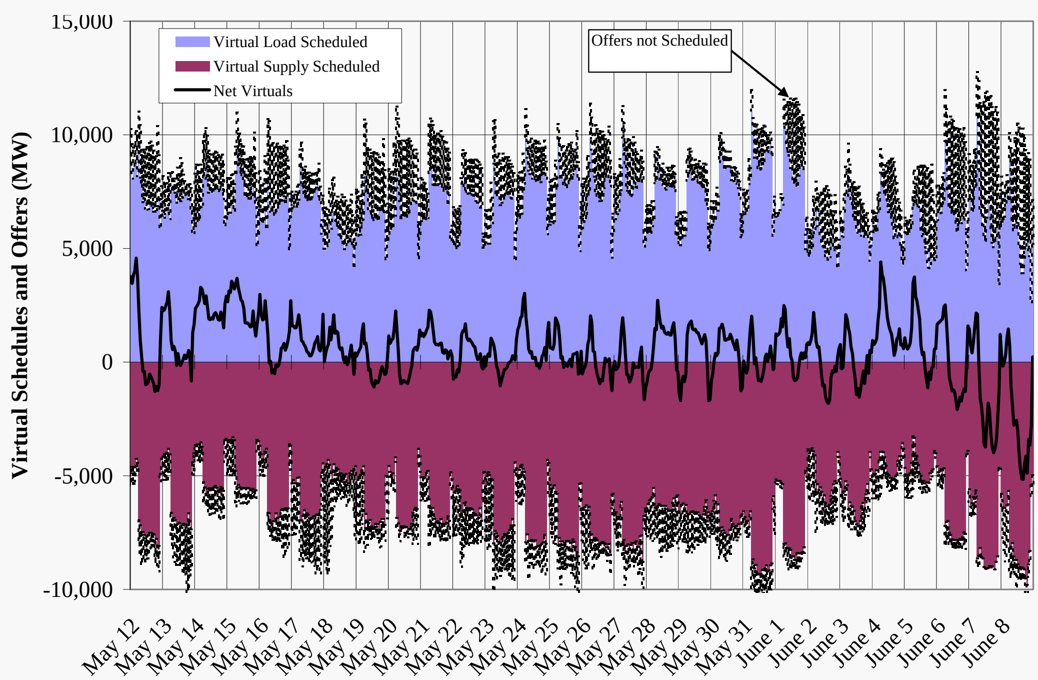
POTOMAC ECONOMICS

Virtual Trading in the Day-Ahead Energy Market

- Virtual trading in the day-ahead market serves to:
  - ✓ The day-ahead market results are efficient;
  - ✓ Facilitate convergence between the day-ahead and real-time prices; and
  - ✓ Mitigate market power in the day-ahead market.
- The following figure shows the virtual load and supply offers and schedules for the past month in the Midwest ISO energy markets.
- Initially, these levels were relatively low relative to other nodal energy markets. However, the quantities of both offers and schedules increased substantially since the start of the market:
  - ✓ Virtual load increased by roughly 200 percent over the period.
  - ✓ Virtual supply increased by more than 400 percent.
- The net virtual load is highly responsive to price differences at different times of the day (e.g., off-peak vs. peak hours).

POTOMAC ECONOMICS

Virtual Load and Supply in the Day-Ahead Market
May 12 to June 8, 2005



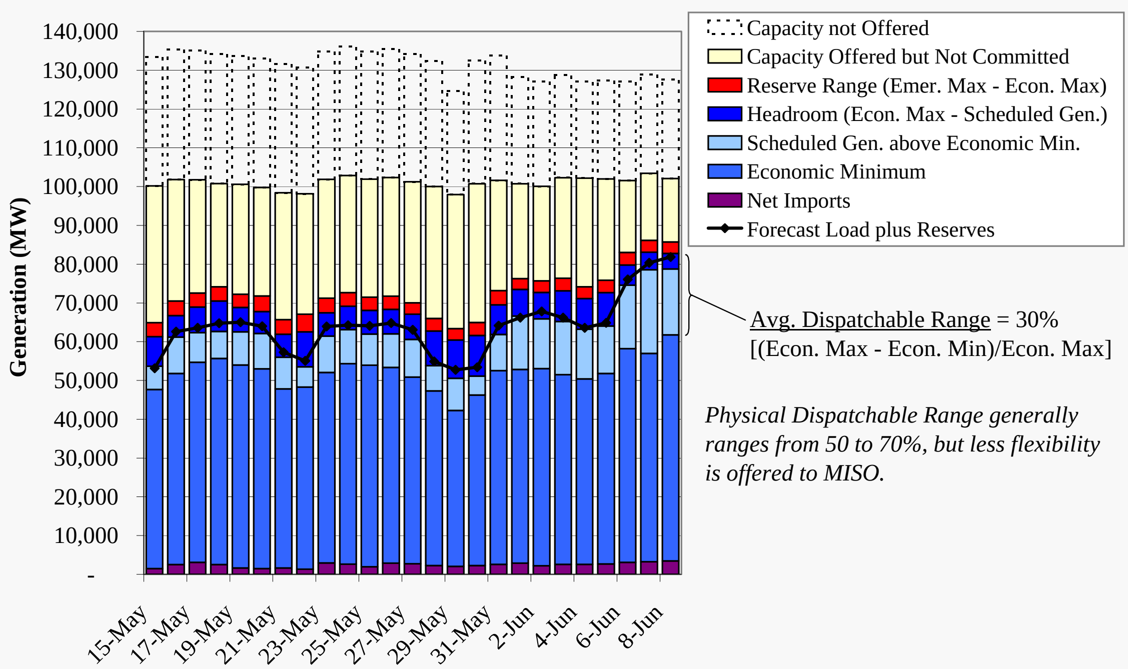
POTOMAC ECONOMICS

Average Day-Ahead Generation and Imports

- The next figure shows the physical supply that is scheduled in the day-ahead market relative to the forecast load.
- The figure shows that total schedules are generally sufficient to serve 90 to 95 percent of the forecast demand.
  - ✓ Additional demand will be served in the real-time market by:
    1. The available headroom on online units,
    2. Peaking resources,
    3. Generation committed through the reliability commitment process;
    4. Additional imports;
  - ✓ Because the forecasted load would generally require all available headroom, some of the other sources of supply are frequently needed in real time.
- The figure shows that roughly 25 GW is not offered in the day-ahead (some of which is on outage). and 30 GW is offered, but not scheduled in the market.
- It also shows that day-ahead schedules increased with load in early June.

POTOMAC ECONOMICS

Average Day-Ahead Generation and Imports
May 12 to June 8, 2005



Physical Dispatchable Range generally ranges from 50 to 70%, but less flexibility is offered to MISO.

POTOMAC ECONOMICS

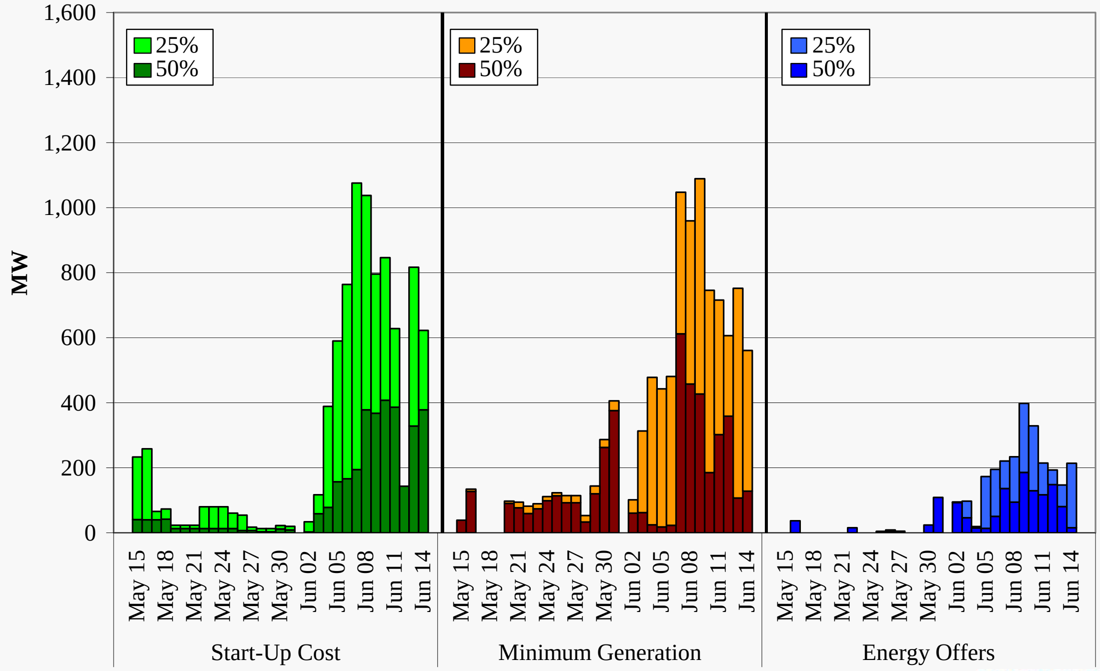
Day-Ahead and Real-Time Net Imports

- Initially, the average import amounts were substantially less than pre-market levels, but the quantity of both day-ahead and real-time net imports quickly increased to more normal.
- The real-time net imports have been much more variable than the day-ahead amounts, largely due to their response to real-time energy prices.
- Our analysis of the real-time market has shown:
  - ✓ Larger total transactions and more volatility than in the day-ahead market.
  - ✓ The transaction quantities and direction have been fairly responsive to significant differences in prices.
- These initial results are encouraging. However, Midwest ISO and PJM should continue to explore market-to-market interface upgrades to optimize the physical interchange.

Expiration of Cost-Based Bidding

- FERC required that participants' offer prices not exceed their costs by more than 10 percent during the first 60 days of operation.
- The cost-based requirement expired on May 31 and participants are now free to offer their resources at prices that substantially exceed their marginal costs.
- The following figure shows that the magnitude of offers with prices more than 25 or 50 percent above variable costs increased when the requirement expired.
  - ✓ Start-up and minimum generation quantities increased by more much more than energy.
  - ✓ The quantities are relatively low.
- The approved market power mitigation measures will be used to ensure that participants do not use this flexibility to exercise market power.

Offers Above Cost-Based Reference Levels
May 15 to June 14, 2005



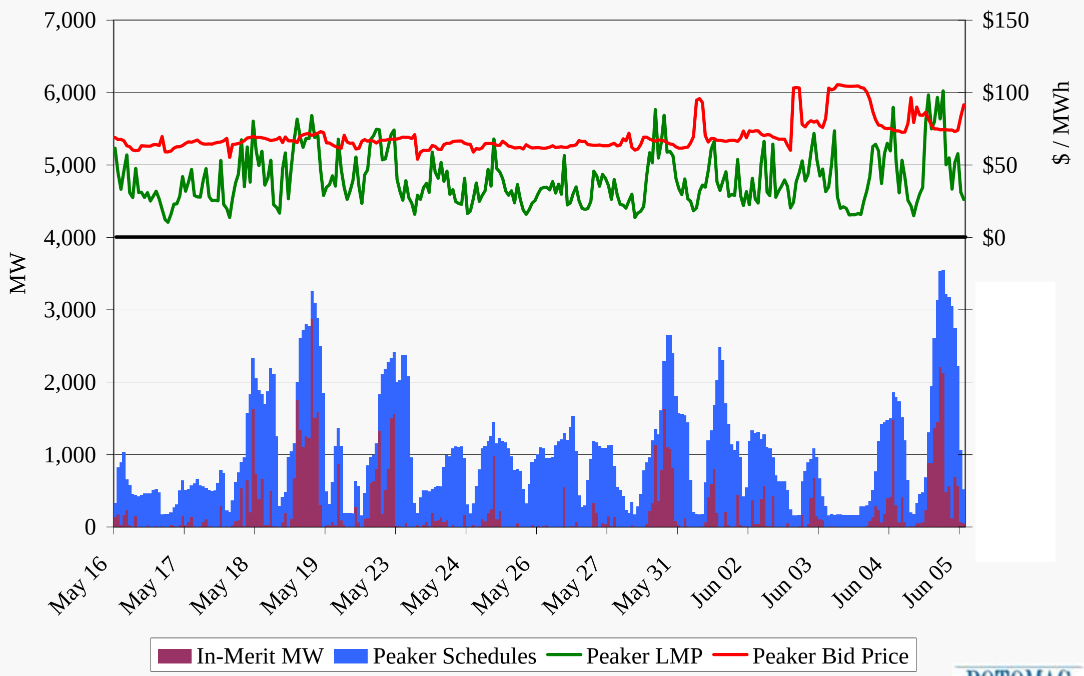
POTOMAC ECONOMICS

Dispatch of Peaking Resources

- Reasons why peakers are dispatched:
  - ✓ Under-purchasing by loads in the day-ahead market causing fewer non-peaking resources to be committed.
  - ✓ High levels of planned outages of non-peaking resources.
  - ✓ Offers by owners of peaking resources that do not fully reflect their true costs of operating, including opportunity costs.
- The dispatch of peaking resources has generally declined over the past two months as resources have come back from planned outages.
- However, the figure shows that
  - ✓ A large portion of the peakers that are dispatched are “out-of-merit” order (their offer price is higher than the LMP).
  - ✓ The average offer prices for the peakers running is often significantly higher than the LMPs at their locations.
- These results confirm the importance of continuing to explore means to increase the ability of the peakers to set energy prices.

POTOMAC ECONOMICS

Dispatch of Peaking Resources
May 16 to June 5, 2005



Other Market Monitoring Questions/Issues

- Development of a capacity market in the Midwest;
- Market monitoring policy statement:
  - ✓ Should not restrict market monitoring activities;
  - ✓ However, the direction to “not undertake any investigative steps” following a referral to the Commission could be a concern; and
  - ✓ Is consistent with the Commissions desire to avoid “delegation” to market monitors.
- Role of the IMM in:
  - ✓ Merger review and analysis;
  - ✓ Advising/communicating with FERC; and
  - ✓ Modifying market rules and tariff provisions;
- Confidentiality of data and information;