Harvard Electricity Policy Group
Forty-Ninth Plenary Session

The Impact of Competition on Electricity Prices: Can We Discern a Pattern?

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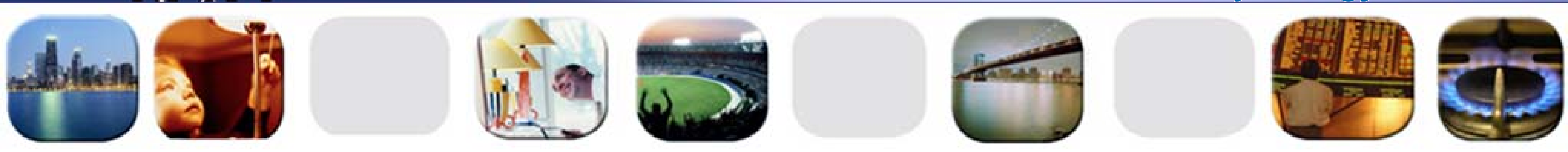

Constellation Energy

Entry, Concentration, and Market Efficiency:
A Simulation of the PJM Energy Market
2003 – 2005

Terry S. Harvill, Ph.D.

The way energy **works.**™

Outline

- Purpose of the Study
- Background: PJM Interconnection and the History of Expansion
- Generator Market Power
- PJM Energy Market Capacity and Concentration
- The Model
- Simulating the PJM Energy Market
- Price Markups from Market Simulations
- Conclusions and Future Research

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Purpose of the Study

- The rapid expansion of the PJM energy market during 2004 and 2005 provides a unique opportunity to test the theory of market concentration and its effect on market efficiency.
- This research tested the hypothesis that, for a given number of generating units in the industry, system marginal price will be a decreasing function of the number of owners or generators controlling the units (i.e., the industry concentration ratio).
- A refined competitive benchmark model was developed to assess price-cost markups in the PJM energy market during three distinct periods of expansion:
    1. Pre-Commonwealth Edison integration,
    2. Pre-American Electric Power (AEP), Dayton Power and Light (DPL), Duquesne Light (Duquesne), and Dominion Virginia Power (Dominion) integration, and
    3. Post-AEP, DPL, Duquesne, and Dominion Integration.
- Specifically, the study applied market simulation methods to assess price-cost markups to the PJM energy market over the May 1st to August 31st periods in 2003, 2004, and 2005, respectively.

Purpose of the Study

- In 2001, the Federal Energy Regulatory Commission proposed a Standard Market Design to unify the best practices in market design and to enhance competition in electricity markets under its jurisdiction. Currently, every U.S. electricity market is seeking ways to improve its market design based on its regional realities.

- The evaluation of the electricity market efficiency can help to identify necessary revisions to current markets. Competitive benchmark analysis is a direct approach to evaluate the performance of electricity markets by estimating how much the actual market prices deviate from the perfect competitive benchmark prices based on actual generation costs or cost estimates. Although perfect competition is rarely encountered in the real world, it provides a benchmark against which to compare various markets having different structures. The competitive benchmark approach has been employed in the studies of several electricity markets, including the England and Wales market, the California market, the PJM market, and the New England market.

- Although the competitive benchmark approach can evaluate market performance, it cannot provide the reasons for the market inefficiency. Many issues can contribute to the electricity market inefficiency, such as market design flaws, abuse of market power, and inherent engineering features of power system operations.

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Background: PJM Interconnection

- PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

- Acting neutrally and independently, PJM operates the world's largest competitive wholesale electricity market and ensures the reliability of the largest centrally dispatched grid in the world.

- PJM's members, totaling more than 450, include power generators, transmission owners, electricity distributors, power marketers and large consumers. PJM's role as a federally regulated RTO means that it acts independently and impartially in managing the regional transmission system and the wholesale electricity market.

PJM Interconnection – History of Expansion

- In 2003, PJM operated a centrally dispatched, competitive wholesale electricity market comprising generating capacity of more than 76,000 megawatts and about 250 market buyers, sellers and traders of electricity in a region including more than 25 million people in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.

- In 2004, PJM operated a centrally dispatched, competitive wholesale electricity market comprising generating capacity of approximately 144,000 megawatts and about 330 market buyers, sellers and traders of electricity in a region including more than 45.3 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

- In 2005, PJM operated a centrally dispatched, competitive wholesale electricity market comprising generating capacity of 163,471 megawatts and about 390 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM grew substantially in 2005 as the result of the integrations of new members from parts of Virginia, North Carolina, Maryland and Pennsylvania.

PJM Interconnection – History of Expansion

- Phase 1 (2004) – The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, and the Allegheny Power Company (AP) Control Zone.

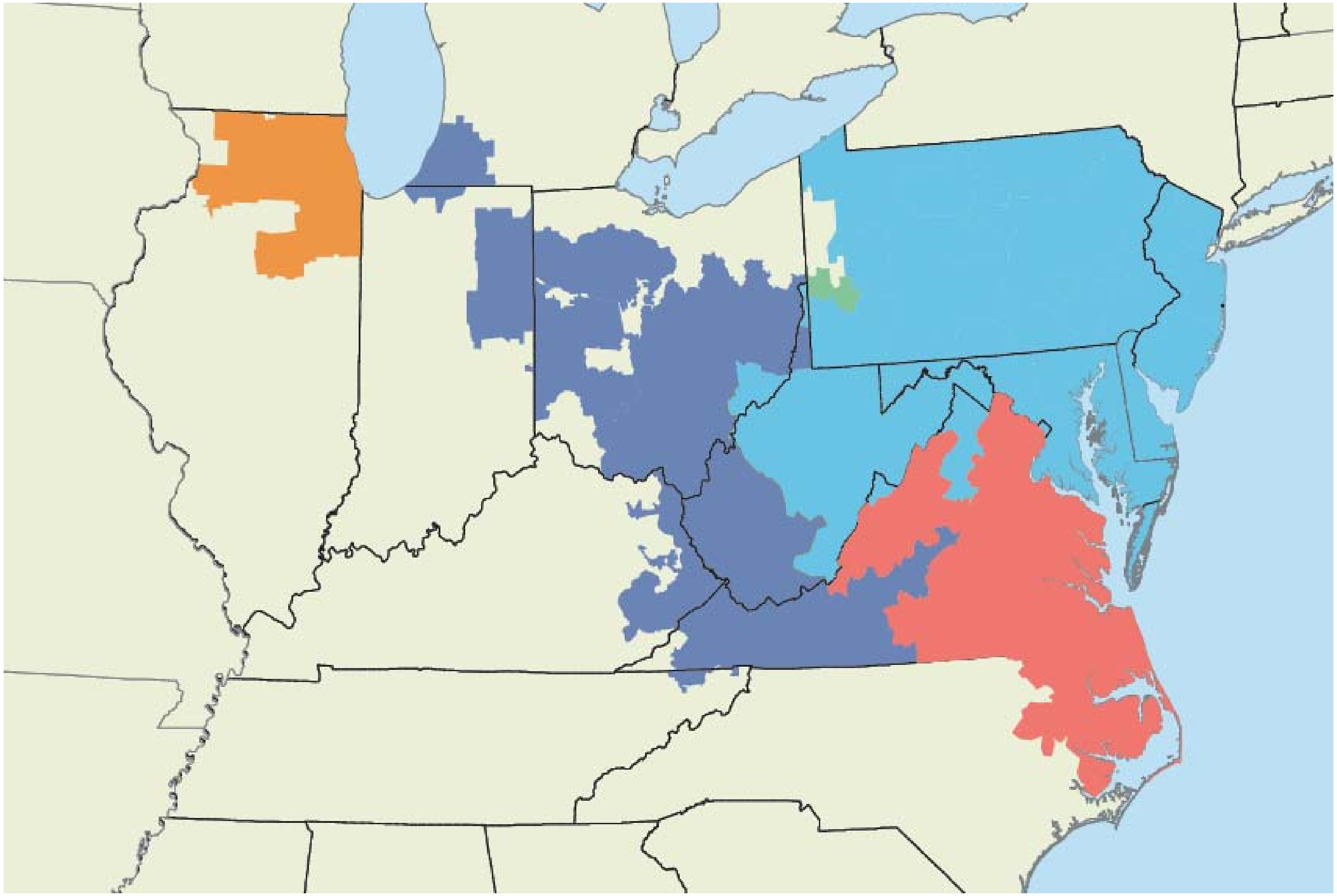
- Phase 2 (2004) – The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).

- Phase 3 (2004) – The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- Phase 4 (2005) – The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- Phase 5 (2005) – The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone.

PJM Interconnection – History of Expansion



Legend

- Phase 1
- Phase 2
- Phase 3
- Phase 4
- Phase 5

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Generator Market Power

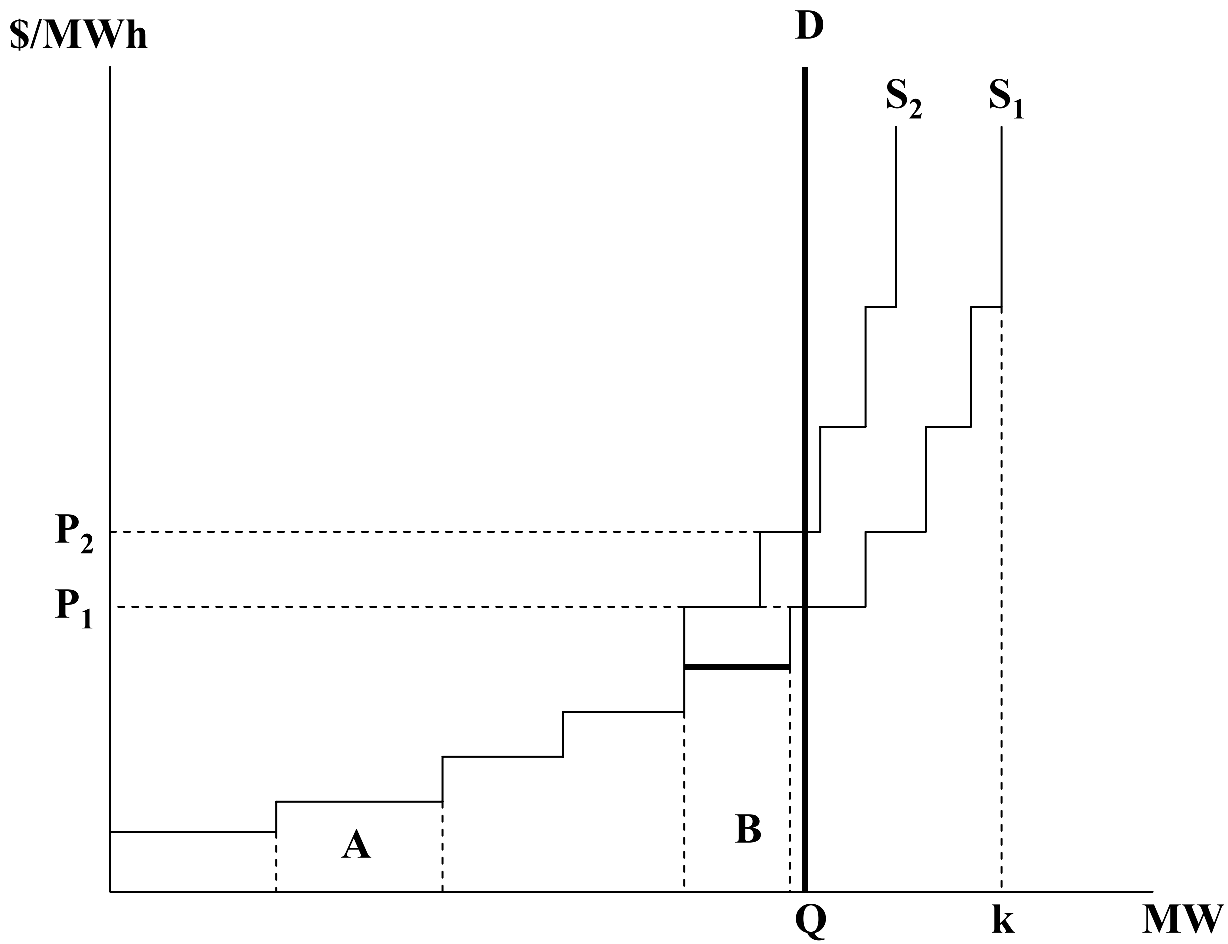
- Market power is the ability to profitably raise price above competitive levels (Carlton and Perloff, 1994, 8).
- Unusual characteristics of electricity markets enhance the potential for market power abuse by generators.
- Unlike most commodities, electricity cannot be stored or inventoried to meet swings in demand.
- Electricity generators must be available in real time to meet fluctuations in demand.
- Hourly demand levels are predictable and the capacity constraint of the market and of market participants is common knowledge.
- Further, the short-term price elasticity of demand is nearly perfectly inelastic as virtually all customers are shielded from real-time fluctuations in price.
- These market characteristics, when coupled with the expectation of high demand, present generators with the opportunity to move prices above marginal costs.

Generator Market Power

- von der Fehr and Harbord (1993) show that a generator who increases the offer price of one unit will have an external effect on other units because the generator raises the expected system marginal price.
- An owner who controls many units will internalize part of this externality.
- This internalization creates an additional incentive for the generator to increase its offer prices.
- This "coordination incentive" is increasing in the number of units an owner controls.
- von der Fehr and Harbord conclude that for a given number of generating units in the industry, system marginal price will be a decreasing function of the number of owners or generators controlling the units.
- Thus, the industry concentration ratio serves as an indicator of the incentives that generators have to unilaterally act to increase prices above marginal cost as well as an indicator of the potential for coordinated behavior among suppliers.

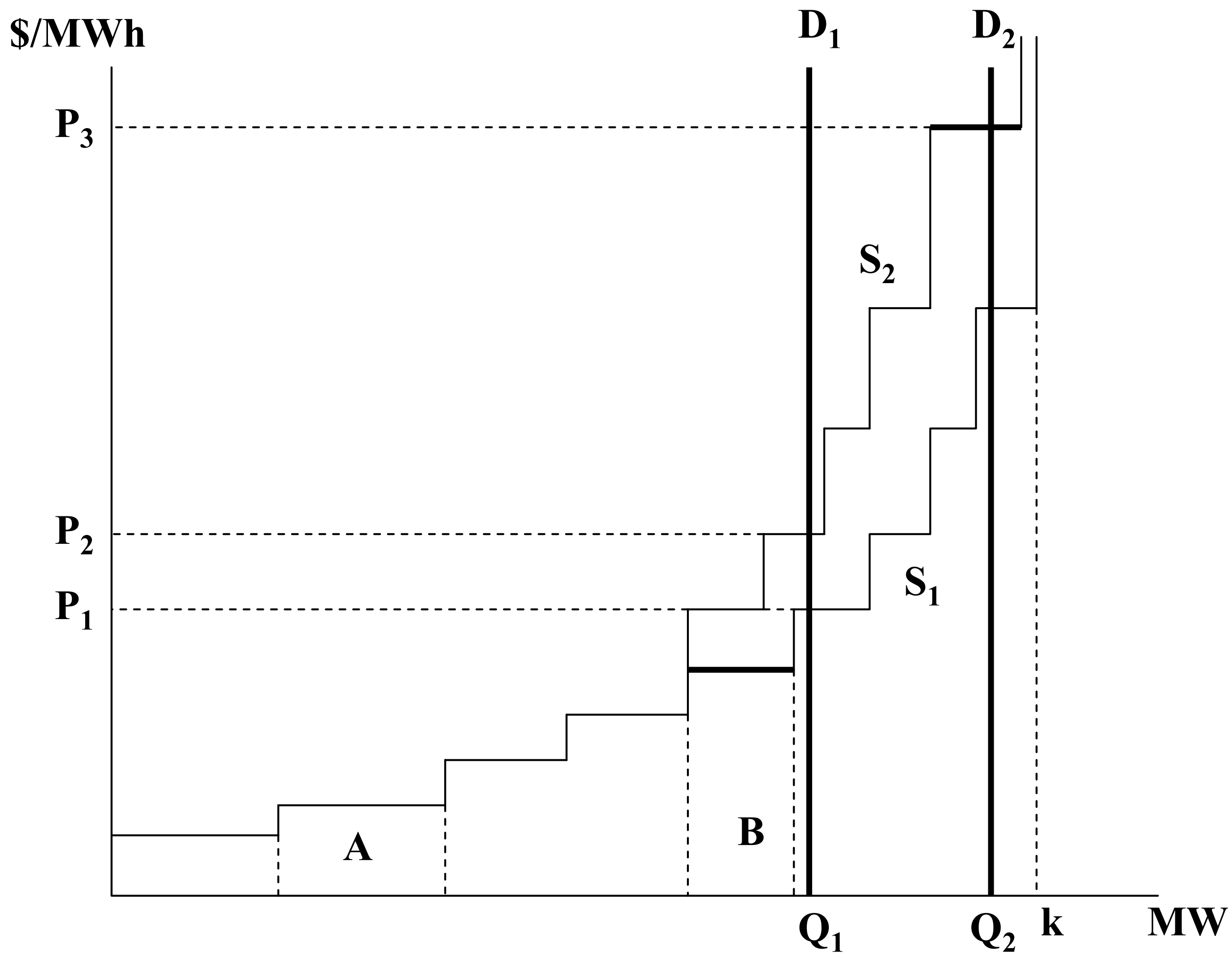
Generator Market Power

- A generator can increase profits by unilaterally withholding its capacity from the market by not offering bids for some of its units.



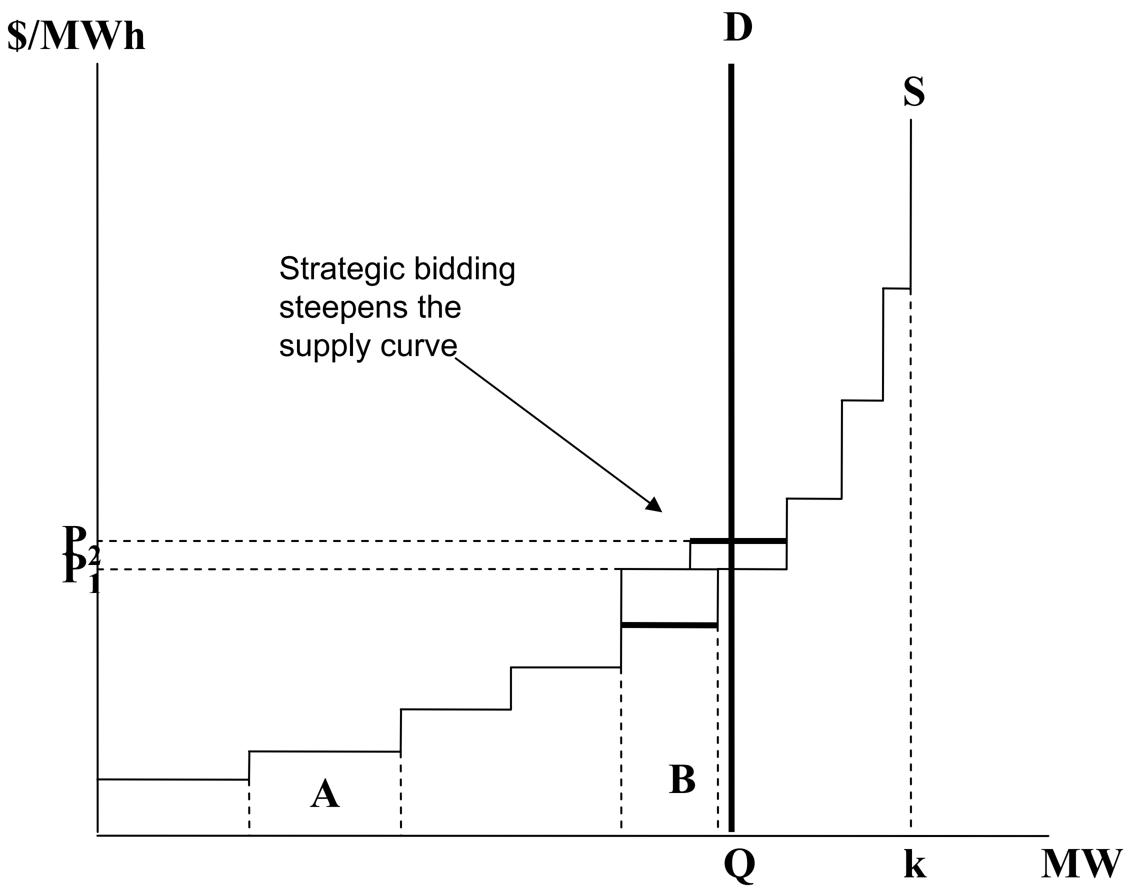
Generator Market Power

- An alternative to physically withholding units from the bid stack is for a generator to offer uneconomic bids for some of its units.



Generator Market Power

- Generators can strategically determine the bid of a unit relative to its marginal costs based upon the economic characteristics of its overall generating unit portfolio.



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PJM Energy Market Capacity

- The total summer generating capacity of generating units located within PJM's control totaled 74,241 megawatts in 2003.
- In 2004, the PJM summer generating capacity increased by 37 percent or 27,717 megawatts to 101,958 with the addition of the generating units located in the Commonwealth Edison service territory.
- In 2005, PJM's summer generating capacity increased by another 61 percent or 62,214 megawatts to 164,172 megawatts with the addition of the generating units located in the service territories of American Electric Power Company, Dayton Power and Light Company, Dominion, and Duquesne Light Company.

PJM Energy Market Concentration

- The most widely used structural measure of concentration in a market is the Hirschmann-Herfindahl Index (HHI).
- An appeal of the HHI is that it is linked directly to market power in the theoretical Cournot model of competition (Tirole, 1988).
- The HHI ranges from zero for a perfectly competitive market to 10,000 for a monopoly.
- In 1986, the United States Department of Justice (DOJ) adopted new guidelines which employ the Hirschmann-Herfindahl Index to measure the market concentration. The DOJ regards an HHI of 1,000 as a breakpoint. An HHI below 1,000 indicates that the market is reasonably competitive and market power should not be a concern. With an HHI between 1,000 and 1,800, the market is considered moderately concentrated. The DOJ interprets an HHI above 1,800 as an indication of a highly concentrated market.
- Because regulated industries have not historically been competitive, the DOJ adopts a less restrictive standard for regulated industries. For example, the DOJ has declared that in the oil pipeline industry, an HHI below 2,500 still indicates workable competition.

PJM Energy Market Concentration

- Although the HHI is still used in the practice of antitrust review, it has some serious deficiencies.
  - First, this index is calculated by using the market share a firm possesses, but the market share can be calculated using any number of units of measure. For instance, in the utility industry, a utility company's market share can be measured in terms of revenues, capacities (e.g., generation or transmission capacities in the electric industry), or even the number of customers it serves. Depending on the physical and cost characteristics of the product or service being sold, the choice of a different unit of measure can cause different results.
  - Second, in order to apply the HHI, the relevant market must be identified. Defining those markets is influenced in different ways by different characteristics. Among those characteristics are reliability issues which may confer local market power to a particular generating utility, transmission constraints which make transmission service between certain areas impractical on a cost effectiveness basis, or even geographic constraints such as mountain ranges or large bodies of water. Without a well-defined relevant market, the market share calculation can be meaningless.

PJM Energy Market Concentration

- Nevertheless, the HHI is a reasonable tool to employ to quickly and directly evaluate the concentration of a market.

- Accordingly, the HHI is calculated for the PJM energy market for 2003, 2004, and 2005, respectively.

  – In all three years, the HHI falls below the DOJ threshold of 1,000 thereby indicating that the PJM market should be reasonably competitive and market power should not be a concern.

  – Again, the HHI calculation does not take into account the numerous idiosyncrasies of electricity and the PJM energy market.

  – The HHI calculations also show that market concentration decreased each year from 2003 to 2005 as the market expanded to include additional utility service territories in the Mid-Atlantic and Midwestern areas of the United States.

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The Model

- A perfect competitive benchmark model has the following major assumptions:
  1. all firms are assumed to produce homogeneous, divisible output;
  2. no entry or exit barriers;
  3. consumers have full information;
  4. total supply exceeds total demand;
  5. no transaction costs; and
  6. each firm is competitive or acts as price-taker.

- Under these assumptions, a firm will produce electricity and sell at its marginal cost as long as the marginal cost is less or equal to market price.

The Model

- For the wholesale market, the marginal cost can be defined as the incremental cost to supply the next megawatt energy demand of the system.
- To estimate the hourly market-clearing prices for the PJM energy market, assuming perfectly competitive behavior, the development of a simulation model was necessary.
- The construction of the aggregate marginal cost curve and several adjustments made to actual hourly demand data were necessary in order to more accurately reflect the requirements placed on internal generation resources.

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Simulating the PJM Energy Market

Supply Side Considerations -- Marginal Costs

- Marginal costs are computed by multiplying the average heat rate (Btu/kWh) of each unit by the cost of the energy that it consumes ($/Btu). Marginal costs should also include an additive measure for non-fuel variable operations and maintenance expenses. Finally, variable costs associated with compliance to emissions reduction programs should also be reflected in the marginal cost of generating electricity.

$$MarginalCosts_{it} = \left(\frac{MMBtu}{MWh}\right)_i * \left(\frac{FuelCost}{MMBtu}\right) + SO2Cost_{it} + NOxCost_{it} + VarO\&M_i$$

Simulating the PJM Energy Market

Supply Side Considerations -- Derivation of Forced Outage Factors

- National average unit unavailability statistics were obtained from the North American Electric Reliability Council (NERC). NERC maintains a database on unit outage information from all of the regional reliability councils in the country. The released data are classified by unit type and capacity. Multiplying the capacity of each unit *i* by its derived FOF and summing across *x* units in the market gives the expected forced outages of capacity for any hour in the PJM energy market:

$$E(ForcedOutages)_{PJM} = \sum_{i}^{x} cap_i * FOF_i$$

Simulating the PJM Energy Market

Supply Side Considerations -- Derivation of Forced Outage Factors

- Generating units suffer unplanned, forced outages that stem from many causes. Forced outage factors provide for a downward adjustment to total summer-rated capacity available to the market. This adjustment is accomplished through Monte Carlo simulations.
- I use national unit unavailability statistics obtained from the North American Electric Reliability Council. Following BBW (2000) and using data elements from the NERC database, the forced outage factor for a unit is defined as:

$$FOF = 1 - \frac{EquivalentAvailabilityFactor}{1 - ScheduledOutageFactor}$$

- As explained by BBW (2000, 39), the derived forced outage factor, FOF_{BBW}, gives the fraction of the time that a unit was not available for production due to unplanned causes. Each unit in PJM is assigned a derived forced outage factor according to unit type and megawatt rating.

Simulating the PJM Energy Market

Supply Side Considerations -- Derivation of Forced Outage Factors

- The NERC database includes many data elements, one of which is labeled “forced outage factor” that is defined as:

$$FOF_{NERC} = \frac{ForcedOutageHours}{PeriodHours}$$

- The NERC forced outage factor is more broadly defined than the FOF_{BBW}. The numerator, forced outage hours, does not account for partial outages where the unit is operable but not at full capacity. The denominator, period hours, includes scheduled outage hours for planned maintenance. As a result, FOF_{NERC} underestimates the amount of capacity will be unavailable due to unplanned causes.

Simulating the PJM Energy Market

Supply Side Considerations

- After the availability of each unit is determined, an aggregate supply curve is constructed.
- The market-clearing price is determined by the marginal cost of the most expensive unit required to meet hourly demand.
- One hundred simulations were conducted for each hour.
- The expected marginal cost is the average of the 100 simulated marginal cost values.

Simulating the PJM Energy Market

Supply Side Considerations

- More specifically, following BBW (2000), generating units i = 1, ..., n are ordered according to increasing marginal cost.
- The market-clearing price produced by this simulation for the *j*th iteration in hour *h*, $C_{jh}(NetDem_h)$, is the marginal cost of the *k*th cheapest generating unit in hour *h*, where $NetDem_h$ is effective demand in hour *h*. The marginal generator in hour *h* is determined by:

$$k_h = \arg\min x \left| \sum_{i=1}^{x} I(i) * cap_i \geq NetDem_h \right.$$

where I(*i*) is an indicator variable that takes the value of 1 with probability of $1\text{-}FOF_i$ and 0 otherwise.

- For each hour, the Monte Carlo simulation of each unit's outage probability is repeated 100 times. In other words, for each iteration, the availability of each unit is based upon a random draw that is performed independently for each unit according to that unit's forced outage factor.

Simulating the PJM Energy Market

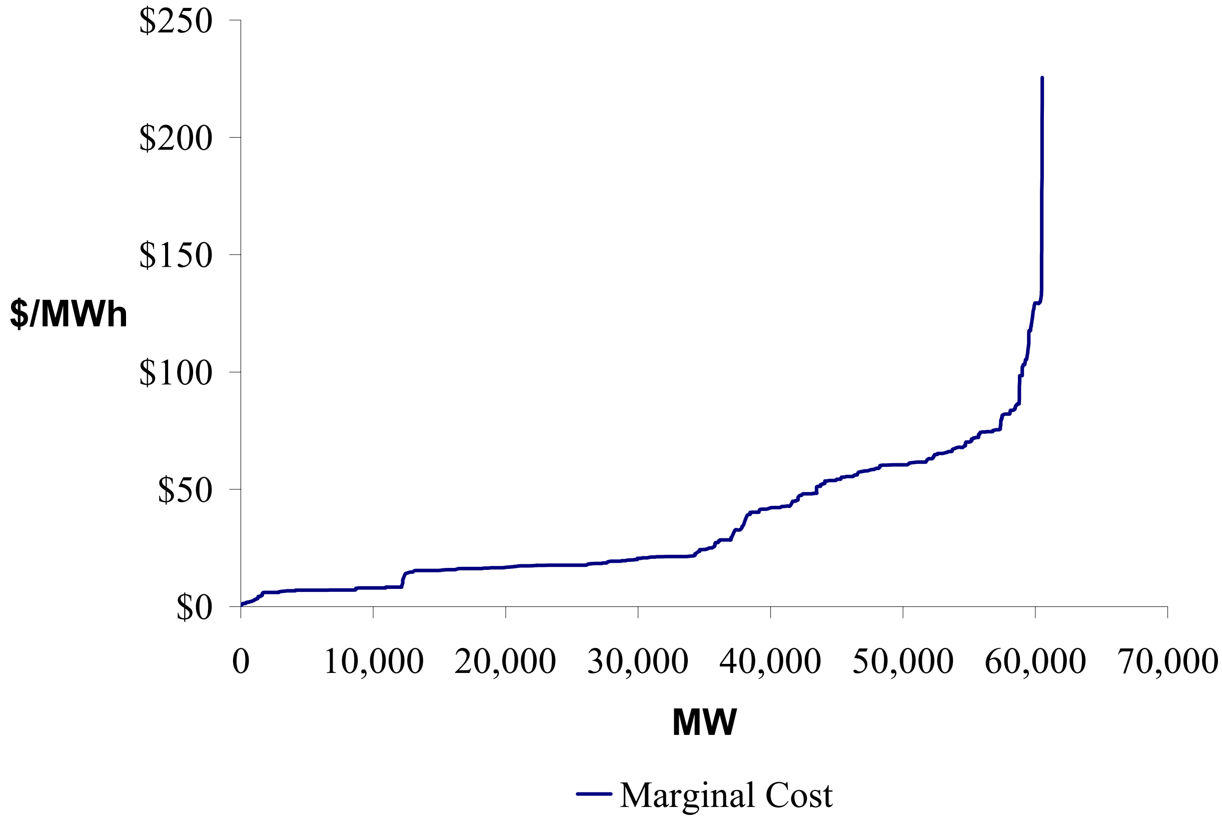
Supply Side Considerations

- The marginal cost at a given quantity for that iteration is then the marginal cost of the last available unit necessary to meet that quantity given the unavailability of those units that have randomly suffered forced outages for that iteration of the simulation.
- Note that for each of the 100 draws from the aggregate marginal cost curve, we will obtain different values of marginal costs and the market clearing price.
- Consequently, we index each of these values by *j*, to denote the number of the draw.
- We can then compute an estimate of the expected value of marginal cost of meeting demand as:

$$\overline{C}(NetDem_h) = \frac{\sum_{j=1}^{100} C_{jh}(NetDem_h)}{100}$$

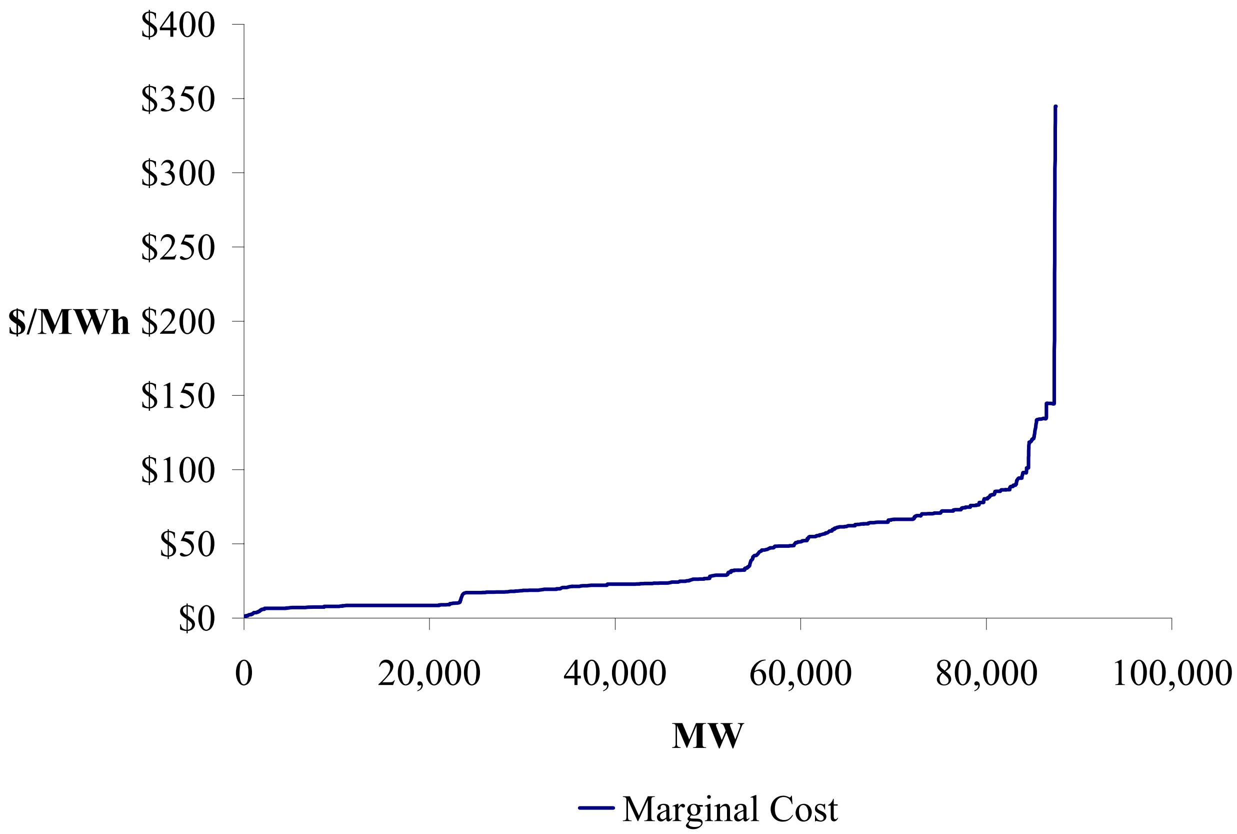
Simulating the PJM Energy Market

- **PJM Aggregate Supply Curve (August 2003)**



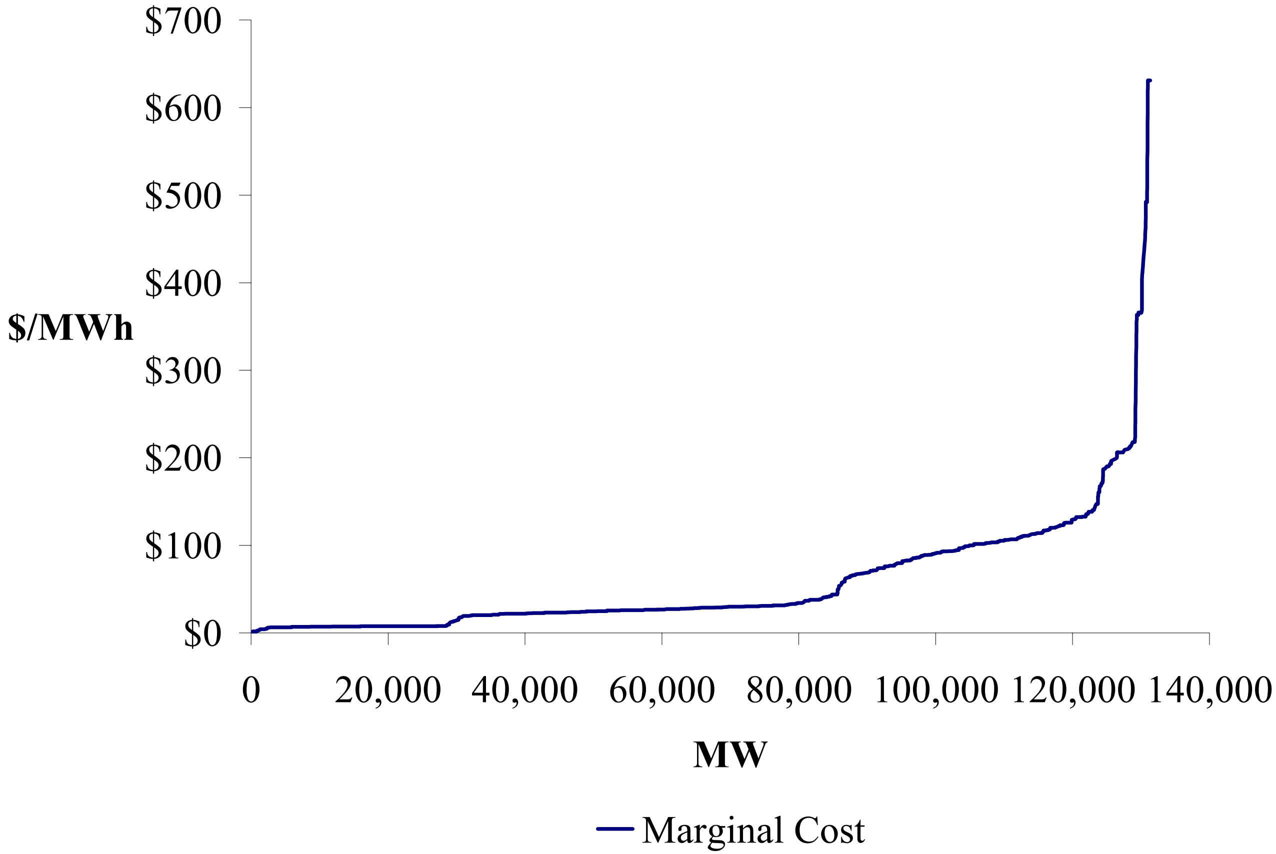
Simulating the PJM Energy Market

- **PJM Aggregate Supply Curve (August 2004)**



Simulating the PJM Energy Market

- **PJM Aggregate Supply Curve (August 2005)**



Simulating the PJM Energy Market

Demand Side Considerations -- Calculation of Hourly Net Demand

- Data on hourly demand can be obtained from PJM via its Internet site. Following BBW (2000), several adjustments to the data will be required to accurately reflect the effective demand faced by PJM generation resources.

- These include adjustments for:
  1. Ancillary Services
  2. Hydro Generation
  3. Net Imports

Simulating the PJM Energy Market

Demand Side Considerations -- Ancillary Services

- Generators provide a number of generation-related products and services which are generically referred to as ancillary services. Regulation service provides near instantaneous supply response to short-term upward and downward changes in demand by maintaining system frequency. Sometimes referred to as automatic generator control (AGC), because generators are automated to respond by increasing or decreasing generation in ensuring power system operations are maintained at 60 hertz.
- BBW (2000) argue that capacity that provides upward regulation is held out of the energy market. More significant is the adjustment made for primary reserve. Primary reserve is unused generation capability that can be fully converted into energy within ten minutes.
- For the simulation, demand was adjusted for each test period in a manner consistent with PJM requirements capacity being held out of the market to respond to contingency situations.

Simulating the PJM Energy Market

Demand Side Considerations -- Hydro Generation

- BBW (2000) and Joskow-Kahn (2001) treat hydro generation as a non-strategic resource. Mansur (2001) holds constant average hourly hydro generation to average hourly load throughout each month.
- For my market simulations, average hourly hydro generation to average hourly load throughout each month is held constant consistent with Mansur (2001).

Demand Side Considerations -- Net Imports

- PJM is both a net importer and exporter of power. An adjustment to hourly demand was needed to reflect that non-PJM resources may, in part, satisfy internal PJM demand. Hourly net imports are subtracted from hourly demand to account for this external source of supply.

Simulating the PJM Energy Market

Demand Side Considerations -- Locational Marginal Pricing

- The PJM market uses locational marginal pricing (LMP) to determine the market-clearing marginal price for energy. LMP prices electricity at the points that it is received into the system and at load centers. In PJM, when the transmission system is not constrained, the price at all points of receipt and delivery is the same. This price is determined by the highest priced generator required to meet system load. However, when parts of the transmission system become constrained, prices will vary by location.

- PJM includes several thousand points where electricity is priced. The points are aggregated into regions and hubs. The largest aggregation is the PJM control area. The PJM-wide reported price during constrained hours is a weighted average price of all nodes. Mansur (2001) argues that the PJM average price can either increase or decrease as a result of transmission congestion. Mansur simulates market-clearing prices for congested hours and computes markups for these hours using the PJM average price.

- Following Mansur (2001), this simulation calculates market clearing prices for all hours and computes markups for these hours using the PJM average price.

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Price Markups from Market Simulations

Derivation of the Load-Weighted Lerner Index

- BBW (2000) develop a market performance measure that Mansur (2001) appropriately labels a load-weighted Lerner index. The Lerner index is a measure of market power. An index value of zero indicates perfectly competitive market behavior. A value of one indicates profit maximizing behavior of a pure monopolist. Thus, values greater than zero present a gauge of the degree of market power (Joskow and Kahn, 2001).
- In developing this market performance measure, the deviation from marginal cost pricing is calculated by taking the difference between the actual market price, PJMPR, and the expected marginal price, C, for each hour *h*. As in Mansur (2001), this difference is weighted by the share of load that is procured from the spot market. Weighting in this manner gives the change in total market costs due to pricing above marginal costs:

$$\Delta TC_h = \left[PJMPR_h - \overline{C}_h\right] * \left[Dem_h * SpotMarketShare\right]$$

Price Markups from Market Simulations

Derivation of the Load-Weighted Lerner Index

- The total cost of energy procured in the market is:

$$TC_h = PJMPR_h * \left[Dem_h * SpotMarketShare\right]$$

- The market performance is equal to:

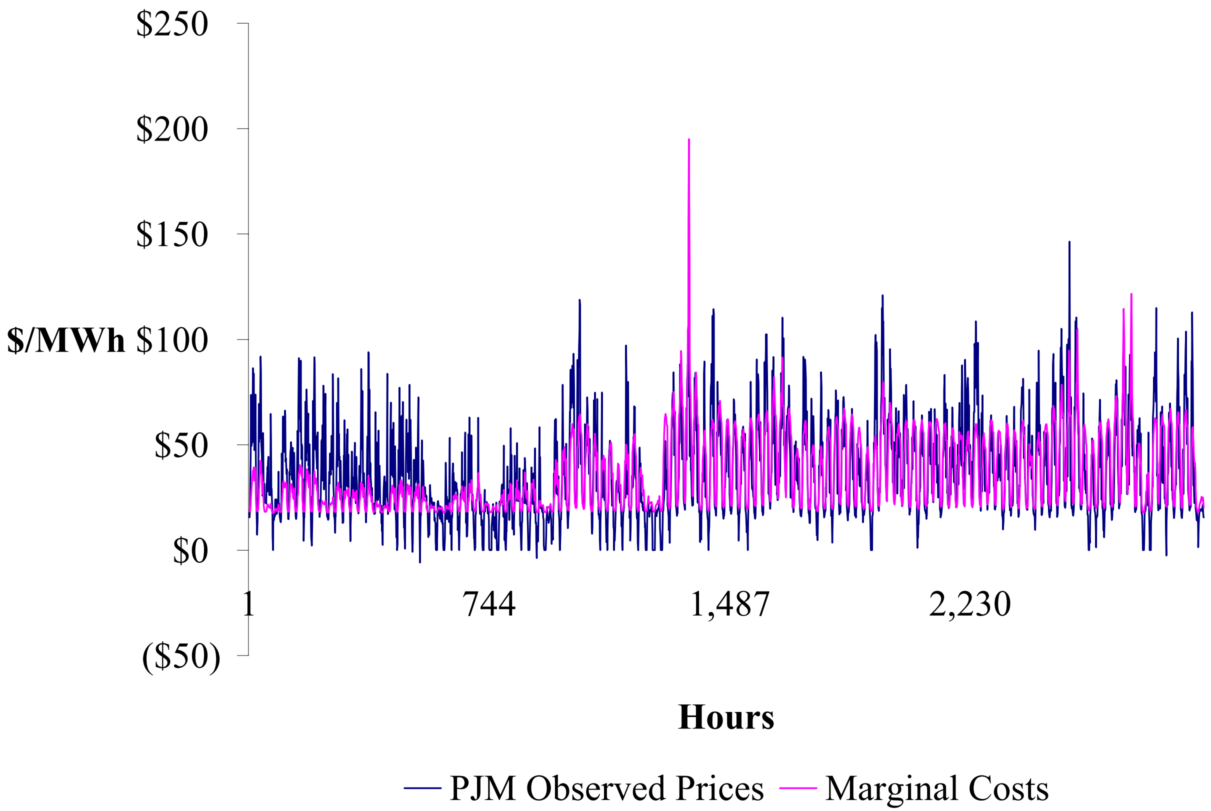
$$MP(S) = \frac{\sum_{h \in s} \Delta TC_h}{\sum_{h \in s} TC_h}$$

where S indicates a selected set of hours.

Price Markups from Market Simulations

Non-Constrained Hours	May-03	Jun-03	Jul-03	Aug-03	May-03 to Aug-03
Average Hourly Demand (MW)	30,281	32,887	37,688	37,587	34,297
Average Mark-Up ($ / MWh)	$ 5.05	$ (8.18)	$ (2.94)	$ (2.24)	$ (1.71)
Market Performance Measure (Percent)	22.44%	-37.17%	-8.91%	-5.46%	-4.42%
All Hours					
Average Hourly Demand (MW)	31,655	36,836	42,363	42,934	38,460
Average Mark-Up ($ / MWh)	$ 8.28	$ (3.69)	$ (1.78)	$ (1.36)	$ 0.40
Market Performance Measure (Percent)	28.19%	-10.24%	-3.69%	-2.48%	0.92%
8 Hour Peak (11 AM - 7 PM)					
Average Hourly Demand (MW)	34,632	41,513	48,592	49,197	43,499
Average Mark-Up ($ / MWh)	$ 14.33	$ (0.59)	$ 0.49	$ 1.95	$ 4.09
Market Performance Measure (Percent)	35.12%	-2.27%	0.95%	3.23%	6.44%

Price Markups from Market Simulations

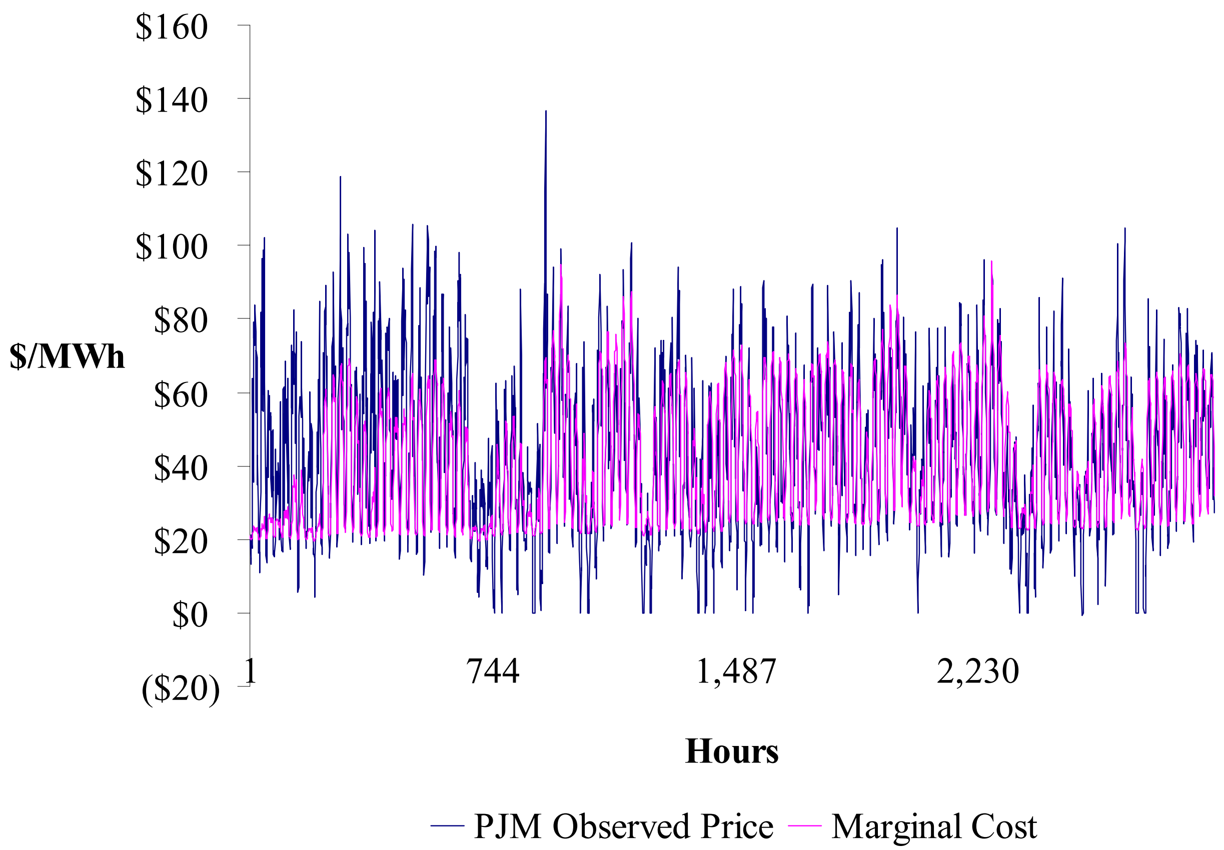


2003 Expected Marginal Cost and Observed Prices
(May 1, 2003 to August 31, 2003)

Price Markups from Market Simulations

Non-Constrained Hours	May-04	Jun-04	Jul-04	Aug-04	May-03 to Aug-03
Average Hourly Demand (MW)	NA	39,294	42,100	40,576	39,918
Average Mark-Up ($ / MWh)	NA	$ (20.93)	$ (23.94)	$ (22.90)	$ (21.79)
Market Performance Measure (Percent)	NA	NA	NA	NA	NA
All Hours					
Average Hourly Demand (MW)	50,025	54,101	57,924	56,677	54,687
Average Mark-Up ($ / MWh)	$ 13.20	$ (2.07)	$ (3.35)	$ (4.09)	$ 0.95
Market Performance Measure (Percent)	27.45%	-4.36%	-7.46%	-9.08%	1.72%
8 Hour Peak (11 AM - 7 PM)					
Average Hourly Demand (MW)	55,344	60,817	65,503	63,743	61,356
Average Mark-Up ($ / MWh)	$ 19.93	$ 0.42	$ (2.18)	$ (2.81)	$ 3.87
Market Performance Measure (Percent)	30.09%	0.27%	-3.71%	-4.57%	5.38%

Price Markups from Market Simulations

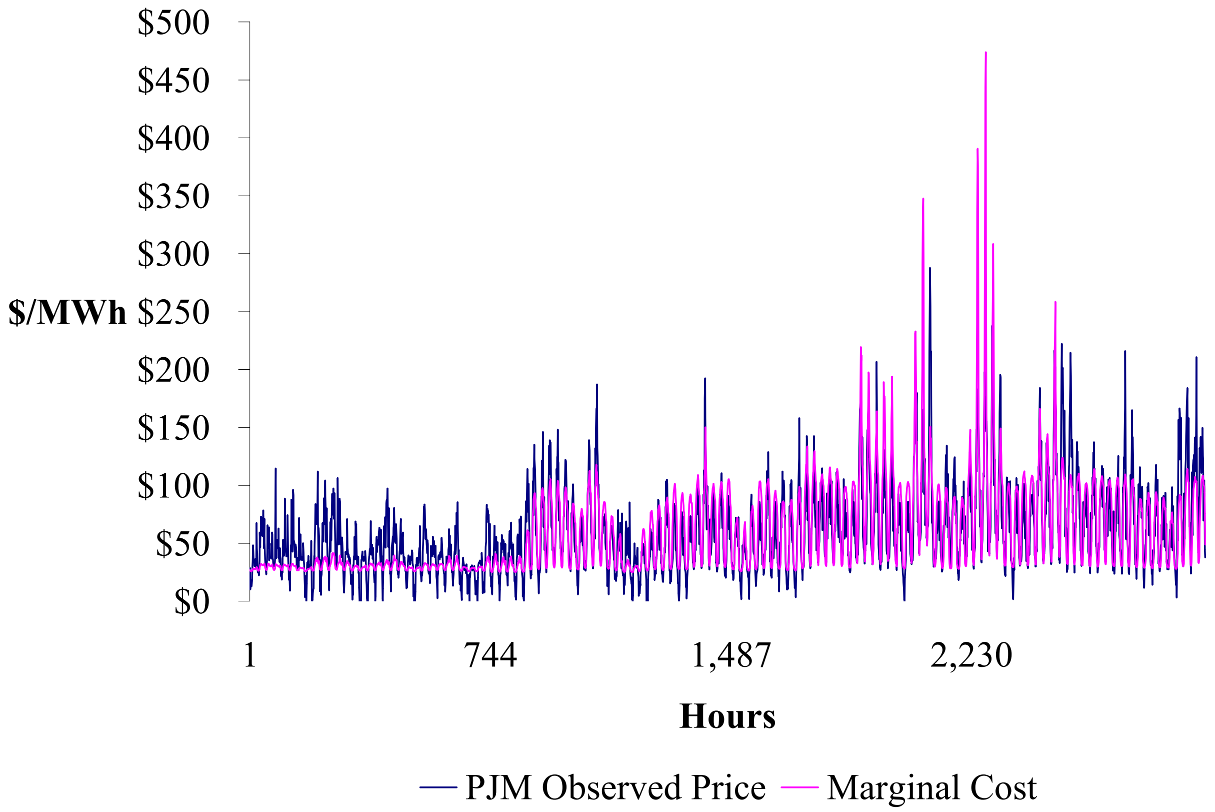


2004 Expected Marginal Cost and Observed Prices
May 1, 2004 to August 31, 2004

Price Markups from Market Simulations

Non-Constrained Hours	May-05	Jun-05	Jul-05	Aug-05	May-05 to Aug-05
Average Hourly Demand (MW)	67,548	73,946	84,645	92,717	73,147
Average Mark-Up ($ / MWh)	$ (0.87)	$ (12.28)	$ (10.59)	$ (8.21)	$ (5.22)
Market Performance Measure (Percent)	2.98%	-53.39%	-23.78%	-15.11%	-13.99%
All Hours					
Average Hourly Demand (MW)	71,369	91,949	98,187	99,627	90,269
Average Mark-Up ($ / MWh)	$ 9.46	$ (2.90)	$ (10.82)	$ (1.09)	$ (1.33)
Market Performance Measure (Percent)	26.84%	-5.21%	-16.97%	-2.52%	-3.70%
8 Hour Peak (11 AM - 7 PM)					
Average Hourly Demand (MW)	77,101	104,762	111,819	113,304	101,722
Average Mark-Up ($ / MWh)	$ 19.33	$ 2.20	$ (12.41)	$ (2.35)	$ 1.69
Market Performance Measure (Percent)	38.46%	2.29%	-13.42%	-3.34%	-0.52%

Price Markups from Market Simulations



2005 Expected Marginal Cost and Observed Prices
May 1, 2004 to August 31, 2004

Price Markups from Market Simulations

Negative Markups

- The market simulations highlight the prevalence of computed negative markups in the simulation results.
- Many of the off-peak periods in particular are characterized by negative markups where the expected marginal cost exceeds the observed price.
- Unit commitment constraints are believed to largely account for these results.

Price Markups from Market Simulations

Unit Commitment Constraints

- As noted in BBW (2000), the simulated market-clearing prices do not take into account the dynamic effects of unit commitment constraints, including start-up costs, ramping rates, and minimum down times.
  - Start-up costs generally range from $20 to $40 per megawatt.
  - Ramping rates refer to how rapidly a unit can increase its output.
  - Minimum down times are associated with the time required to bring a generating unit up to its minimum generating limit, once it has been shut down.
- These constraints are intertemporal in nature since the cost of production depends of the levels of production in other periods (McGuire, 1997, 2) and represent significant opportunity costs associated with unit shut down (BBW, 2000, 28).

Price Markups from Market Simulations

Unit Commitment Constraints

- Steam-fossil units bid their start-up costs separately from their bids to provide incremental energy.
- The PJM scheduling algorithm takes these costs into account by projecting market-clearing prices over a multi-day horizon to ensure that projected market-clearing prices are sufficient to recover unit start-up costs and marginal costs over the start-up to shut-down cycle.
- In contrast, the simulation model assumes instantaneous availability and dispatch of total unit capacity, if its computed marginal cost is the least cost alternative in meeting incremental demand.
- Unit commitment constraints are not addressed within the simulation modeling framework.

Price Markups from Market Simulations

Unit Commitment Constraints

- The PJM scheduling algorithm, however, takes as given all self-scheduled capacity. Recall that generators in PJM are allowed to self-schedule their generating units. The PJM spot market is available in real time to procure any additional supply needed to meet load requirements not sufficiently met by self-scheduled generation. Clearly, if self-scheduled capacity is sufficient to meet all of the off-peak load requirements, then the market price would fall to zero. Over the 12 months of the simulation, the observed market-clearing price was zero for 161 hours. Demand averaged over 36,000 MW over these hours.

- More generally, during off-peak hours, if a substantial amount of base load capacity is self-scheduled, then there is no guarantee that units with the lowest marginal costs are utilized to meet demand. Productive inefficiency would occur if units with higher marginal costs are self-scheduled relative to units that are not dispatched for production. This would leave lower-cost units available to meet incremental load requirements and lead to observed market-clearing prices that are less than those simulated by least-cost dispatch.

Price Markups from Market Simulations

Unit Commitment Constraints

- The treatment of start-up costs complicates identifying productive inefficiency.
- Owners of self-scheduled units may choose to operate their units during off-peak hours, even if their marginal costs are higher than the market price as a means of avoiding unit shut-down and the subsequent start-up costs to meet demand during the next on-peak period.
- Data is not available from PJM to determine to what extent this might occur.
- The scenario is consistent with simulated marking-clearing prices less than observed prices during the off-peak periods.

Price Markups from Market Simulations

Performance of the Market

- The results of the market simulations for the May 1 to August 31 periods for 2003, 2004, and 2005, indicate that the performance of the market improved with the addition of new market participants in 2004 and 2005.

- The results of the simulation indicate that the load-weighted Lerner index decreased to -0.52 percent in 2005 from 6.44 percent in 2003.

- The addition of Commonwealth Edison in 2004 significantly increased constraints within the PJM energy market and likely impacted the observed prices in PJM during 2004 due to the lack of a significant link to the other PJM market participants.

- This deficiency was somewhat addressed in 2005 with the addition of American Electric Power.

Outline

- Purpose of the Study
- Background: PJM Interconnection and the History of Expansion
- Generator Market Power
- PJM Energy Market Capacity and Concentration
- The Model
- Simulating the PJM Energy Market
- Price Markups from Market Simulations
- Conclusions and Future Research

Conclusions and Future Research

- This research contributes to the literature in three important aspects.
  - First, competitive benchmark models were developed to evaluate the PJM energy market taking into account deficiencies in previous research.
  - Second, the results of the analysis provide a measure of market efficiency for the three years during which the PJM energy market rapidly and substantially expanded.
  - Third, and most importantly, this research validated the Federal Energy Regulatory Commission's policies of encouraging participation in Regional Transmission Organizations.

Conclusions and Future Research

- Models were developed to analyze the efficiency of the PJM energy market during a period of rapid and substantial expansion.
- Over the May 2004 to May 2005 timeframe the PJM interconnect expanded to twelve states and the District of Columbia.
- During that time, PJM added four large new utility members creating a link between PJM's Mid-Atlantic and Midwest grid areas, and its load-serving capacity doubled to approximately 160,000 MW.
- Specifically, this research tested the hypothesis that, for a given number of generating units in the industry, system marginal price will be a decreasing function of the number of owners or generators controlling the units (i.e., the industry concentration ratio).
- Models were developed to analyze the efficiency effects new, large market participants joining the PJM energy market from May of 2003 to May of 2004.

Conclusions and Future Research

- These market efficiency analysis models were applied to the PJM energy market by simulating its operation for three distinct periods over the course of three years.

- The results show that the addition of additional market participants, while increasing congestion on the PJM transmission system, did in fact increase the overall efficiency of the market by decreasing price markups over marginal costs.

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