

Competitive Energy Options for Pennsylvania

by

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A Report To The Team Pennsylvania Foundation

*This report is the work of its principal authors and does not necessarily represent the views of the
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STUDY SCOPE

The Team Pennsylvania Foundation requested that the Carnegie Mellon Electricity Industry Center at Carnegie Mellon University undertake a study of the electric power sector options available to the Commonwealth to ensure that Pennsylvania has a competitive business environment. The study was conducted from October 13, 2006 to January 11, 2007.

Team Pennsylvania Foundation recognizes that it is critical to understand how the electricity sector and its pricing will impact the competitiveness of Pennsylvania's business climate. As a significant amount of research has already occurred, the Foundation decided to focus its efforts on identifying and analyzing the options available to the Commonwealth. This study was designed to yield a statewide comprehensive analysis of policy options available to ensure competitive energy pricing in the Commonwealth. The study tasks were as follows.

Task 1.1 – Compile and evaluate the various policy and technical options that have been already recommended to maintain competitive electricity prices in Pennsylvania.

- This will include a review of the research detailed in relevant reports already created on this issue including the Report to the Allegheny Conference on Community Development dated August 5, 2005.
- This will include a full review of the relevant comments filed before the Public Utility Commission during its current proceedings.
- This may also include review of relevant policy and technical changes that have taken place in other deregulated markets.

Task 1.2 – To more fully understand the impacts of the various options available to the Commonwealth, it may be necessary to perform research on certain components of the electricity market including but not limited to load serving entities, electricity customers, regional rate structures, and tariff documents. The extent of this research will be decided by the researchers, with final approval from the Team PA Foundation. This research should include the surveying of a prepared list of Team Pennsylvania Foundation partners and any key stakeholders recommended by the Electricity Industry Center.

- In order to ascertain the impacts on both small and large businesses, and both industrial and commercial end-users, research will take into account all commercial and industrial rate classes.
- Identification of the primary drivers of wholesale electricity prices including fuel sources and prices as well as any other factor significantly contributing to the wholesale price.
- Identification of the primary drivers of retail electricity prices including fuel sources and prices, transmission costs and any other factor that significantly contributes to retail prices.
- Analysis of the how increased use of alternative energy sources affects competitive markets and rates for industrial and commercial end-users.
- A comparison of the energy cost factors including regulatory compliance, and taxes (including the PA Gross Receipts Tax) in Pennsylvania compared to other deregulated states.
- Evaluate the impact of the termination of rate caps in other states.
- Study will take into account the entire Commonwealth.

Task 2.1 – Identification, analysis, and recommendation of technical, market and regulatory options available to the Commonwealth, the Public Utility Commission, and other regulatory agencies.

- Detail the options that have the potential for the greatest positive impact on the competitiveness of electricity rates in the Commonwealth.
- Analyze and describe the pros, cons, and expected fiscal impacts of each relevant option.

CARNEGIE MELLON ELECTRICITY INDUSTRY CENTER

This study was performed by members of the Carnegie Mellon Electricity Industry Center (CEIC). The Center was established in 2001 with joint core funding from the Alfred P. Sloan Foundation and the Electric Power Research Institute. CEIC's primary mission is to work with industry, government and other stakeholders to address the strategic problems of the electricity industry.

Eighteen CMU faculty members from seven departments and three adjunct faculty are members of the Center. Eighteen students are currently pursuing doctoral degrees in the Center, and four post-doctoral fellows are performing research in the Center. Thirteen PhD dissertations have been completed in the Center. 93 papers describing the results of Center research have been published in peer-reviewed journals, in addition to 26 books or sections of books, 63 CEIC working papers and 11 special topic reports, such as this one.

Members of the Carnegie Mellon Electricity Industry Center

- chair the Environmental Protection Agency's Science Advisory Board,

- chair the National Research Council Committee on Enhancing the Robustness and Resilience of Electrical Transmission and Distribution in the United States to Terrorist Attack,

- chair the National Academy of Sciences Panel on the U.S. Department of Energy's Carbon Separation & Sequestration R&D Programs,

- chair the Environmental Protection Agency's Science Advisory Board's Homeland Security Subcommittee,

- serve on the Department of Homeland Security's Science and Technology Advisory Committee, and

- serve as the President of the Society of Risk Analysis.

STUDY METHOD

In conducting this study, we have interviewed 45 individuals representing 28 organizations. In addition, we compiled comments made on the subject of the study by 13 individuals representing 12 organizations at a meeting hosted by the Team Pennsylvania Foundation on August 21, 2006, and the comments made by the Team Pennsylvania Foundation Board members present at their November 29, 2006 meeting. We also attended and compiled comments made by 19 presenters at the October 20, 2006 "Energy Summit 2006: Generating Ideas for Southwestern Pennsylvania".

We have reviewed all the comments filed pursuant to Pennsylvania Public Utility Commission Docket No. M-00061597, adopted May 19, 2006 (a summary is included in the body of this report).

In the course of this study we have reviewed 16 published studies of restructuring in the U.S. electricity sector, including research papers, industry-sponsored consultant studies, and reports for public utility commissions in other states.

For this study we have performed four new modeling tasks to estimate the effects of real time pricing, demand-side management policies, generation policies, and certain aspects of the Advanced Energy Portfolio Standard on prices in Pennsylvania.

EXECUTIVE SUMMARY

Pennsylvania's commercial and industrial customers are concerned that electricity prices in the Commonwealth put them at a disadvantage with respect to competitors in nearby states. Retail rates (averaged over all rate classes) in three neighboring states increased by 13 to 118% when rate caps expired in those states. At the end of 2010, rate caps will have expired throughout Pennsylvania. Data compiled by the Industrial Energy Consumers of Pennsylvania indicate that load serving entities in the Commonwealth expect rate increases from 30 to 75 percent when the caps are lifted. The Pennsylvania Office of the Small Business Advocate reports that commercial customers have similar expectations.

This study examines the electricity prices offered to commercial and industrial customers and evaluates options for competitive electricity prices for commercial and industrial customers.

We have identified and analyzed policy options available for competitive energy pricing in the Commonwealth. The largest savings for commercial and industrial customers are obtained through self-generation for applicable customers and overall reduction of demand in the state. Benefits are large both for those participating in these two programs and for other customers. Programs designed to reduce demand (including real time pricing) could lower prices at approximately the same time the remaining rate caps expire. To continue those savings as the economy of the Commonwealth grows, new plants should be designed with available mechanisms that preserve competition but do not perpetuate the current way their output is bid into the hourly auctions. Options for rapid action also are at hand, including modifications to the gross receipts tax, providers of last resort (POLR) switching requirements, and targeted allocation of transmission rights. A reasonable portfolio of these options could offset rate increases as large as 60% for commercial customers and 35% for industrial customers. Larger savings are possible for targeted customers. An option to stabilize or reduce the price of natural gas in the Commonwealth is also feasible, and is being implemented in Indiana.

From 1990 to 2006, electricity sales to Pennsylvania commercial, residential, and industrial customers grew 50%, 33%, and 6% respectively. Regionally, the Commonwealth is a low-cost generator of electricity, exporting \$3.8 billion of electricity, one third of total generation from Pennsylvania plants. The electric power sector is a major Pennsylvania employer, with approximately 16,000 full-time-equivalent jobs.

Pennsylvania's electricity prices are at the median of nearby states: Kentucky, West Virginia, and Ohio have lower electricity prices for all rate classes, while New York, New Jersey, and Maryland have higher prices. For commercial customers, the latter three states average 12.87 cents per kilowatt-hour (kWh), compared to Pennsylvania's 8.97 ¢/kWh and 6.96 ¢/kWh for the average of the three lower priced states. For industrial customers, the average of the three higher priced states is 10.23 ¢/kWh, Pennsylvania's average is 6.47 ¢/kWh, and 4.48 ¢/kWh is the average price in the three lower priced states. Absent subsidy, we expect prices in the lower price states to rise by approximately 1 ¢/kWh as these states are forced to implement air pollution control standards.

11.5% of Pennsylvania commercial and industrial customers purchase power directly from competitive suppliers; the rest buy power at the rate offered by the load serving entity, most of which are still regulated. Many of the former monopoly utilities sold some of their generators and now purchase power for their customers in the open market. Most of this power is transacted in one year contracts, but 15% is transacted in the spot market operated by the three Regional Transmission Organizations in the Commonwealth, of which the PJM Interconnection is the largest.

Many commercial and industrial customers are concerned that rates will rise abruptly when the rate caps expire, and a few have seen large rate increases in territories where they have already expired. There have been benefits of electricity restructuring, including labor efficiencies, capital investments in

upgrades to nuclear plants, and transparency of market data. While restructuring was expected to lower electricity prices by allowing customers to select their suppliers and by forcing suppliers to cut costs or perish, a study conducted in 2006 for the Virginia Corporation Commission noted, “The evidence suggests that, at least so far, no discernable benefit can be seen for customers in restructured states once the rate caps have expired. Increasingly the evidence is beginning to now suggest that prices for customers in restructured states may actually be increasing faster than for customers in states that did not restructure.”

Several aspects of the deregulated market contribute to price increases for commercial and industrial customers.

1. Low cost generators in Pennsylvania have exported power to higher priced markets in New York, New Jersey, and Maryland, resulting in higher prices in Pennsylvania. These exports have benefited customers in the high priced states and the generators, as well as created electricity industry jobs in Pennsylvania.

2. While large industrial customers were valued highly by utilities in the past, they now find their credit-worthiness challenged and are regarded as less valuable than some large commercial customers in negotiating bilateral contracts with suppliers. Some industrial customers report that they are unable to negotiate prices lower than the provider of last resort (POLR) rates, in contrast to some large commercial customers who report that they have negotiated rates that are 30-40% lower than POLR rates.

3. The deregulated market pays all suppliers the market clearing price; since natural gas or oil sets the market clearing price in parts of PJM for all or part of 75% of the hours, the average market clearing price is much higher than the unit cost of electricity from baseload plants, such as coal and nuclear plants. [See section 3.1.1 for further discussion of the hours in which high priced generators set the market clearing price.]

In addition to these deregulation aspects, current Pennsylvania energy policies influence electricity prices. At the time that rate caps expire in the majority of Pennsylvania, the Advanced Energy Portfolio Standard (AEPS) will not change electricity costs significantly, and the AEPS helps by providing incentives for new generation. The subsidy for plants burning waste coal will probably lower electricity prices slightly while the mandate for 800 megawatts (MW) of solar photovoltaic power will raise prices after 2015 above what the price would be if the power were supplied by another renewable source, wind energy, unless solar costs fall significantly compared to wind. The Commonwealth should continue to monitor the costs of solar photovoltaic power as the large-scale implementation deadline approaches. Coal and nuclear fueled baseload plants are the low-cost generators at present and are expected to continue that role. While policies should continue to reach for high environmental quality, administrative actions that impede the development of coal mines, coal plants, and nuclear plants, or that put more stringent environmental standards on these plants will raise costs.

Many commercial and industrial customers report that they have not enjoyed the benefits they expected from electricity deregulation. Much of the price increases seen in recent years stem from the expiration of contracts that offered reduced prices in anticipation of competition. Rising fuel prices, the need for new generation, and new transmission lines to more expensive states are forecast to push up electricity prices as regulated prices are freed. However, the lower prices in nearby states are likely to rise as these generators install expensive environmental controls.

Policy Options to Lower Prices to Industrial and Commercial Customers

Policy options that benefit commercial and industrial customers can either involve subsidies from other rate payers or tax payers, or they can make the system more efficient and lower costs to all. If

subsidies or tax relief are considered, we recommend using a metric of jobs created, direct and indirect, per dollar of subsidy compared to other economic development proposals. Although the metric cannot be calculated with precision, it focuses attention on the goal.

It is commonly believed that in restructured states, industrial customers now pay a larger share of the electric power bill than they did under regulation. We find that this is not generally true either in Pennsylvania or in nearby states. None of these states have seen a change in the relative price (compared to residential customers) for commercial and industrial customers since 1990, except for Ohio which seems to be subsidizing industrials less than it did before restructuring [See section 4.8.3 of this report].

Some of the options discussed could be undertaken quickly, while others require years to implement; some could be done by the Governor while others require legislative approval, and still others would require or benefit from agreement with other states or require approval from the Federal Energy Regulatory Commission (FERC). We summarize the policy options briefly.

The first three options can be in place rapidly, and become effective prior to or simultaneous with the expiration of the rate caps in the majority of the Commonwealth.

Eliminate the Gross Receipts Tax [Section 4.8.2 of this report]. Pennsylvania imposes a gross receipts tax on electricity produced in the Commonwealth. The tax (paid by generators) might be forgiven for selected industrial and commercial customers for economic development. However, the Commonwealth should be careful to avoid a perception that it offers subsidies to attract new employers, but then raises taxes on existing employers to pay for the subsidy. Forgiving the gross receipts tax would lower the price of electricity 0.5 cents for commercial customers and 0.4 cents per kilowatt-hour for industrial customers, if the generators were required to pass the tax savings on to customers. Repealing this tax for all in-state customers would forego \$730 million per year in revenue at current prices; if it were targeted to 20% of the customers (by revenue), the foregone tax would be \$146 million. Economically speaking, this would be a transfer from tax payers to favored electricity customers. If the perceptions by customers and suppliers are correct that electricity prices will increase when rate caps are removed in the majority of the state, the Commonwealth will receive increased revenue from the tax, a portion of which might be used to offset price increases.

POLR Switching Notification and Long-Term Contracts [4.3.1 and 4.4.1]. To facilitate competition, Pennsylvania has insisted that the load serving entity (LSE) obtain electricity via short-term (usually one year) bilateral contracts or in the hourly auction market. The Commonwealth also insists that customers can leave the LSE at any time for a competitive supplier and return to the LSE and receive the POLR rate. This requirement is costly for the LSE and for customers who do not switch. The LSE is required to sell power at a fixed rate and cannot contract for power in a long-term contract that matches the time pattern of supply and demand, both because customers can leave and return freely and because long-term contracts are forbidden. The efficiency of service would be increased by having the service obligation and purchase obligations match more closely. We suggest offering customers contracts with specified rates that are lower the longer the customer commits to not switch; each contract would have an opt-out penalty. More generally, the LSE should be free to enter into contracts with its customers that are of a mutually acceptable length. The LSE should be free to seek supply contracts that have time commitments consistent with the demand side contracts. Long-term POLR or other supply contracts can also provide incentives for new generation. We estimate that annual benefits from reducing this POLR risk premium are \$230 million, lowering commercial prices by 0.3 cents per kWh and industrial prices by 0.2 cents per kWh, if the LSE is required to pass the savings on to customers.

Targeted FTR Allocations [4.6.2]. Another rapid option would be to reassign financial transmission rights (FTR). Some of these rights have been assigned to POLR providers. The Public

Utility Commission (P.U.C.) could reassign some of the FTRs to particular customers, giving them rights worth up to \$300 million annually. However, taking away the FTR would raise POLR costs and prices. This would be a direct transfer of up to \$300 million from current customers to targeted industrial and commercial customers.

The average price for electricity in the market era is greatly increased by high cost plants that are brought into service during the hours of high demand for power. Since all generators asked to supply power during an hour are paid the market clearing price, not calling upon a high cost generator could lower the price paid to all generations from around 20 ¢/kWh to around 8 ¢/kWh. Thus, reducing the use of these expensive peaking plants can have a highly leveraged effect on prices. The following options are designed to reduce the cost of power in the market.

Reduce Demand 5% [4.1.6]. Opportunities abound in the Commonwealth to reduce demand for electricity by increasing the efficiency of use. Demand reduction programs not only save money for the customer reducing demand, but for all customers in the system since prices will decline. A transmission charge could be used to pay the costs of these programs. However, such programs should have peak price reduction as their goal, rather than the multiple goals that raised the costs of some utility demand response programs in the regulated era. The cost of power to commercial customers would decline by 1.4 cents per kilowatt-hour with a 5% demand reduction, and for industrial customers would decline 0.9 cents. The costs of reducing demand by 5% would likely fall between \$400 million and \$800 million. Benefits to the Commonwealth from lower market prices in PJM and less intensive use of peaking generation would be approximately \$1.9 billion.

Real Time Pricing [4.1.4 and 4.1.5]. 15% of the generation capacity in PJM is used only 1.1% of the hours. The incremental cost of the peak demand is more than \$1/kWh. If customers faced the cost of an incremental kWh, they would reduce their consumption significantly. Greater efficiency would be achieved by charging customers the real time price of electricity. Some commercial and industrial customers have gone to real time pricing to lower their electricity bills. We estimate that a real time pricing program could lower prices to commercial customers by 0.3 cents and to industrial customers by 0.2 cents per kilowatt-hour, with a net benefit to all customers. The annual cost of new meters to support widespread real time pricing would be approximately \$138 million, with net annual benefits (after accounting for the cost of the meters) to the Commonwealth of approximately \$230 million. Only a modest number of customers need participate for real time pricing program to be effective in reducing prices for all customers.

Combining a real time pricing program with demand reduction does not give the sum of the benefits listed above, since there is considerable overlap between the behaviors caused by the two programs. Both are worthwhile, but the largest net customer benefit comes from demand reduction programs.

Since economic growth in Pennsylvania increases electricity demand (by approximately 1 to 1.5% in a year), new generation is needed. Other programs to supply generation in ways that preserve competition but do not perpetuate the current way their output is bid into the hourly auctions are required after the first three years of a demand reduction program. We identify the following options.

Co-generation and Microgrids [4.2.1 and 4.2.2]. Some companies need both electricity and process heat. In many cases, co-generation enables the companies to generate electricity at low cost by using the “waste” heat from a generator for process heat. On-site generation of power has the same

highly leveraged effect on prices as do demand reduction and real time pricing. While some industrial customers are co-generators now, hospitals and shopping malls are ideal new commercial candidates for co-generation. Pennsylvania can help inform candidates about the technology and facilitate connecting them to designers and equipment makers; support could extend to subsidies to promote these installations. Currently, a co-generation facility is precluded from selling power to non-owned customers since such a microgrid violates the exclusive right of a utility to sell power in its jurisdiction. Microgrids should be made legal in Pennsylvania. In the restructured market design, microgrids can be structured to benefit the utility as well as the microgrid owner. Another change to enhance efficiency would be to have the microgrid be paid the hourly locational marginal price (LMP) for any power it sells to the grid and pay the hourly LMP for any power it buys from the grid. Insofar as it buys power during peak periods, it should pay a demand charge for that power. A co-generation facility may lower LMPs near it, providing a general benefit but reducing the profit for its owners. Connecticut has addressed this issue by offering a one-time payment of \$500 per kilowatt of installed co-generation capacity. A similar subsidy in Pennsylvania to achieve a 5% demand reduction would require a one-time outlay of \$1.4 billion. We estimate the benefits to be approximately \$546 million annually during the life of the investments. Annual energy savings for commercial and industrial customers would be 0.3 cents per kWh and 0.1 cents per kWh, respectively.

Incentives for New Generation [4.1.7]. The failure of the restructured market to bring in new generation has raised price, particularly during times of peak demand. Pennsylvania, together with other states in PJM, must provide effective incentives for new generation investment, particularly for peaking generators. Pennsylvania and the other states in PJM could provide that incentive by a variety of means, such as loan guarantees, tax-free bonds covering most of the capital costs, negotiated rates to buy electricity over the entire life of the plant, or subsidies for the cost of building the plant. Each of these incentives would provide an incentive to build the new plant and lower its cost of capital, thus lowering its unit costs. They differ in terms of the cost to the Commonwealth of getting a unit reduction in the cost of generating electricity from a plant. For example, a loan guarantee, tax free bond, or life of the plant contract to purchase electricity would involve no direct state outlays, in contrast to a plant subsidy. However, since the Commonwealth has limited borrowing power, all three options would reduce the Commonwealth's ability to borrow in the future or raise the interest rate of future loans. We have not analyzed the options to see which would achieve a unit reduction in the cost of a new plant at the lowest cost to Pennsylvania.

The output of a new baseload plant could be sold to a group of customers at roughly 6.2 cents per kilowatt-hour, higher than current industrial prices, but lower than commercial prices or some forecasts of industrial prices. This would provide a guaranteed price for an industrial or commercial plant.

The greatest advantage is realized if the options discussed above are used to build new peaking plants. The output of a new peaking plant should be bid into PJM. Building enough new plants would effectively put a cap on the market clearing price equal to the generation cost of the new plants. We estimate this market clearing price would be capped at 15 cents per kilowatt-hour, lowering total customer payments about \$4 billion. An investment of \$1 billion to replace the 1900 MW of highly inefficient peaking plants would have a payback period of less than two years to consumers. While building these plants would lower electricity costs more than the capital cost of the plants, the plants would not be able to recoup their capital costs from the PJM auction. The options for covering the fixed costs would be a transmission charge, a tax on electricity, or the state treasury; this is similar to the Connecticut subsidy of \$500 per kilowatt for new plants (see section 2.3.5). Total savings in Pennsylvania would likely be approximately 0.7 cents per kWh. Total savings would be approximately \$860 million annually. Allocating Pennsylvania's savings to commercial and industrial customers based on load yields total annual savings of \$250 million for commercial customers and \$260 million for industrial customers.

A Pennsylvania Power Authority could be established to manage the subsidy, handle the bidding process, allocate the output of the new baseload plants, and manage the process generally.

Change the Market Auction Model [4.1.8]. One way to retain the competitive goals of restructuring while solving some of the current problems is to have the independent systems operator (PJM, for much of Pennsylvania) eliminate the hourly auction in favor of long-term contracts that specify the fixed and variable costs of each generator. This proposal would retain competition at the level of new generation rather than at an hourly market. These contracts would enable PJM to dispatch generation to minimize cost, paying each its fixed and variable costs instead of the market clearing price. To implement this plan, some contracts would have to extend to the full life of a new plant. This proposal would have one of the good qualities of rate of return regulation by paying each generator its costs, rather than the market clearing price. It would ensure sufficient generation capacity. We urge the Commonwealth to investigate this proposal and, if it is attractive, urge PJM and other RTOs to adopt it. The price to commercial customers would decline 0.6 cents per kilowatt-hour and the price to industrial customers would decline 0.4 cents. Changing the PJM auction would likely involve a structural reorganization of PJM, which could equal PJM's original startup cost of \$150 million. Total benefits through lower prices would amount to \$800 million per year.

The following two options are to address issues that are likely to raise prices.

Keep Low Cost Generation [4.1.1]. Some of the current low-cost coal plants do not meet the highest levels of environmental standards. If the owner of a low cost plant decided to close a plant rather than retrofit it with state of the art environmental controls, Pennsylvania should investigate the likely cost to electricity customers of closing this plant. If these costs are high, the public might be better served by subsidizing environmental controls for the plant or purchasing emissions allowances or providing incentives for a new plant. Evaluating the total cost of emissions control to consumers must properly consider both the direct costs of any necessary investments, and the effects of removing some low-cost generation from the PJM dispatch order, which would increase the number of hours high cost gas and/or oil set the market clearing price. A benefit-cost analysis for regulations would consider the dispatch implications. Thus, policies that encourage existing low-cost generation sources to continue operating, even when expensive environmental controls are required, could lower costs to industrial and commercial customers of all classes in the Commonwealth significantly. There is a clear social benefit to producing power with low environmental impact. The Commonwealth might explore direct environmental capital cost reimbursement payments to generators through a wires charge (without a rate of return) to keep these plants economically viable after installation of environmental controls and so that their bids reflect fuel costs.

Other options noted here are to build low marginal cost generation, such as coal and nuclear, that use Pennsylvania's natural and intellectual resources and encourage new generation to locate at mine mouth or close to load, depending on the relative costs and difficulties of transporting coal and transmitting electricity.

Optimize the AEPS for Costs No Greater Than Those of Wind Power after 2015 [4.7]. The Pennsylvania's Advanced Energy Portfolio Standard (AEPS) generally has small net costs or small net benefits for electricity prices. At the time that rate caps expire in the majority of Pennsylvania, the AEPS will not change electricity costs significantly, and the AEPS helps by providing incentives for new generation. The subsidy for plants burning waste coal will probably lower electricity prices slightly while the mandate for 800 megawatts (MW) of solar photovoltaic power will raise prices after 2015 above what the price would be if the power were supplied by another renewable source, wind energy, unless solar costs fall significantly compared to wind. The Commonwealth should continue to monitor the costs of solar photovoltaic power as the large-scale implementation deadline approaches.

While the focus of this study is electricity options, many of the commercial and industrial customers we interviewed are spending a larger fraction of their energy budget on natural gas than on electricity. Other states are implementing programs to stabilize the cost of natural gas through coal gasification.

Coal Gasification Plants [4.5]. The technology for gasifying coal is well known and has been deployed commercially. These plants become attractive when coal prices are low and natural gas prices are high. The price of natural gas is important for electricity as well, since it frequently sets the price of electricity. Natural gas prices have been volatile and rising. Fixing this price could have a major effect on electricity prices. Pennsylvania should encourage these plants (as Indiana has) and investigate the benefits of loan guarantees. Detailed studies of the proposed Indiana project show net annual costs to the state of \$10 million (in the form of loan guarantees for 10 years), and net annual savings to natural gas rate payers of \$145 million.

The options below will improve the planning and climate for power in the Commonwealth.

Expedite Review Processes [4.1.2 and 4.4.3]. The average price for power would decrease if the number of hours in the year in which gas and oil set the market price could be reduced. As noted earlier, one way to accomplish this would be to build more low-cost generation and to preserve the low-cost generation now in the system. Maintaining environmental goals, expediting the approval process for new plants, opening new coal mines, and other reductions in waiting time would lower the cost of new plants. In interviews conducted for this study and in public forums, generators and customers have protested that Commonwealth agencies take too long to review contracts or issue permits. These included permits for opening a new coal mine, siting a new generator, approving a new transmission line, or approving a long-term bilateral contract. Government review of these issues is generally needed, but the decision process can be expedited while still securing public comment and allowing time for staff review.

Advantageous Sites [4.2.3]. The sites of certain underutilized industrial facilities offer special advantages for building new generation plants. Some sites have easy access to fuel and transmission lines and contain space for a new facility.

Transmission Review [4.6.1]. Deregulation requires a larger transmission network to allow all generators to compete for all customers. FERC has given transmission planning authority within the Commonwealth to the three RTOs (PJM, Midwest ISO, New York ISO) whose footprints partially lie in Pennsylvania. The Department of Community and Economic Development should review the transmission plans of these RTOs to determine which investments in transmission would be most advantageous for Pennsylvania consumers.

PJM Forward Markets [4.4.2]. The market for long-term contracts in PJM is hampered because it is not possible to purchase certain required components (for example, regulation) in forward markets. Western states use this market to structure long-term full requirements contracts, encouraging these contracts.

Summary of Quantified Costs Savings

Some of the options identified in this report can be implemented at approximately the same time as the expiration of the remaining rate caps. Other options require more time, either because they require new construction or because they require time to change behavior.

Not all these savings are additive. For example, demand reduction and co-generation have some overlap. However, the following table may be useful in directing effort to options which can either be

implemented quickly or have large potential. As an example, we have modeled a policy which introduces both real time pricing and demand reduction, finding that the savings from both programs together are 1.5 cents per kWh for commercial customers and 1 cent per kWh for industrial customers. Implementing both may still be desirable because it may be less expensive to put in the meters required for real time pricing for targeted customers than to build new peak generation which would still be required in the case of demand reduction alone.

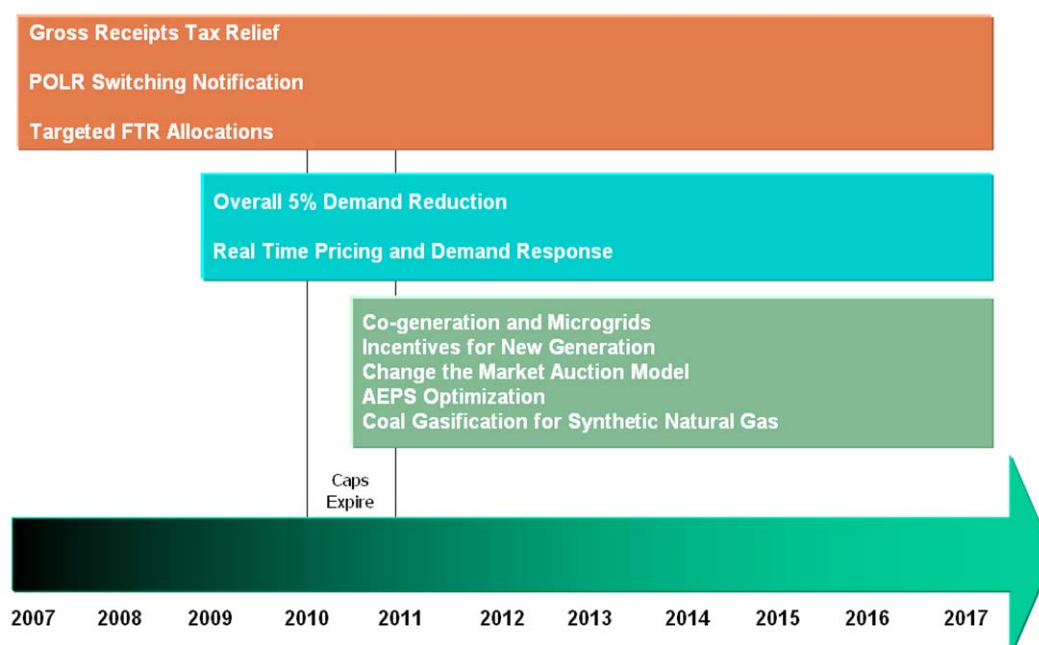
Table 1 shows the estimated savings for commercial and industrial customers of each option in terms of cents per kilowatt-hour of reduced cost of electricity.

	<u>Short Implementation Time</u>		<u>Longer Implementation Time</u>	
	<u>Commercial Customers</u>	<u>Industrial Customers</u>	<u>Commercial Customers</u>	<u>Industrial Customers</u>
Gross Receipts Tax Relief [4.8.2]	0.5	0.4		
POLR Switching Notification [4.3.1]	0.3	0.2		
Targeted FTR Allocations [4.6.2]	0.4	0.3		
Overall 5% Net Demand Reduction [4.1.6]			1.4	0.9
Real Time Pricing and Demand Response [4.1.4 and 4.1.5]			0.3	0.2
Co-generation and microgrids [4.2.1 and 4.2.2]			2.4	1.1
Incentives for New Generation [4.1.7]			0.6	0.4
Change Market Auction Model [4.1.8]			0.6	0.4

*Table 1. Options with quantified customer savings in cents per kilowatt-hour.
Colors divide the options by implementation time.*

The first three programs discussed above can be implemented rapidly, if immediate price relief is desired. The second block of options reduce demand. Although these are continuing, load growth requires that they be augmented after approximately three years by options to produce new generation and also preserve competition but do not perpetuate the current way their output is bid into the hourly auctions (the third block). Finally, optimizing the AEPS should occur prior to the large requirements for solar photovoltaic power, if the costs have not declined to those of wind power.

In addition to options shown in table 1 to reduce electricity cost the Commonwealth also has the option to reduce and stabilize the cost of natural gas by using coal gasification to make synthetic natural gas. Such a program could stabilize gas prices in the Commonwealth at approximately \$7 per million BTU as discussed in section 4.5 (the recently announced Indiana program is to supply 20% of that state's gas at \$6.10 per MMBTU).



While cost savings to customers are one metric by which programs are judged, Pennsylvania's annual costs and benefits are another. Table 2 summarizes estimates for the options identified here.

	Annual Costs	Gross Annual Benefits
Gross Receipts Tax Relief [4.8.2]	\$145-730 million	\$145-730 million
POLR Switching Notification [4.3.1]	Small	\$230 million
Targeted FTR Allocations [4.6.2]	\$300 million	\$300 million
Overall Net Demand Reduction of 5% [4.1.6]	\$400-830 million	\$1,900 million
Real Time Pricing & DR [4.1.4 and 4.1.5]	\$140 million	\$370 million
Co-generation and microgrids [4.2.1 & 4.2.2]	\$160 million ^a	\$1,000 million ^b
Incentives for New Generation [4.1.7]	\$180 million	\$860 million
Change Market Auction Model [4.1.8]	\$20 million	\$800 million
Coal Gasification Plants [4.5]	\$10 million	\$145 million ^c
Keep Low Cost Generation [4.1.1]	Not Yet Quantified	Not Yet Quantified
Advantageous Sites [4.2.3]	Small	Not Yet Quantified
PJM Forward Markets [4.4.2]	Small	Not Yet Quantified
Transmission Review [4.6.1]	Small	Not Yet Quantified
Cross-Subsidies [4.8.3]	Small	Transfer

^a annual value of \$1.4 billion initial payment, 20 year payback at 10%.

^b valued based on achieving 5% of Pennsylvania's demand as co-generation or self-generation with a \$500 per kW subsidy.

^c numbers from the Indiana SNG project.

Table 2. Annual costs and benefits for options.

1. THE ELECTRICITY MARKET IN PENNSYLVANIA

1.1 Electric generation and sales in the Commonwealth

Pennsylvania is the third largest generator of electric power in the nation.¹ The electric generation, transmission, and distribution sector in the Commonwealth employs approximately 16,000 full-time-equivalent personnel. Approximately one-third of the electricity generated at Pennsylvania plants is exported to other states; the net exports have an annual wholesale value of approximately \$3.8 billion.

Annual retail sales of electricity within the Commonwealth total \$12.4 billion. 35% of the power (as measured in megawatt-hours, MWh) is sold to residential customers. 33% is sold to industrial customers, and 31% to commercial (one percent is used by a fourth sector, transportation).

Sales to industrial customers within Pennsylvania since 1990 have grown slowly. Commercial and residential sales have seen steady growth. Figure 1 shows the monthly sales² for the commercial and industrial sectors since 1990. Residential sales have been also growing briskly, and have been larger than sales to the industrial sector since 2002. Total growth from 1990 through 2006 was 6% for industrial sector sales, 50% for commercial, and 33% for residential. Forecasts indicate that 500 megawatts (MW) of new generation will be required annually to supply Pennsylvania's growth³.

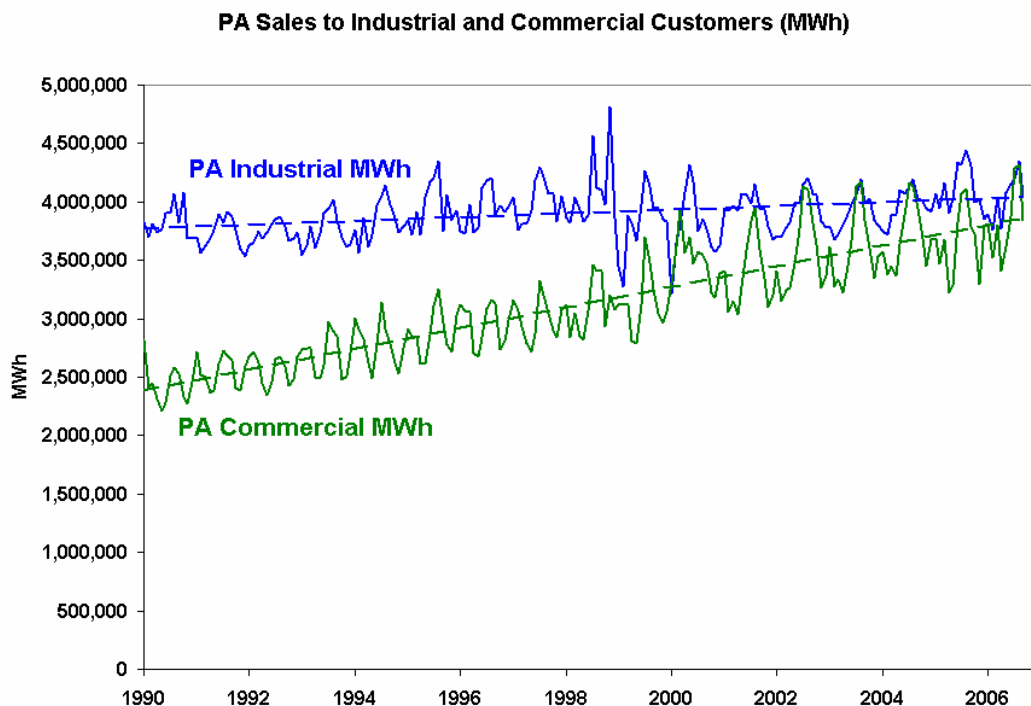


Figure 1. Monthly sales of electric power (in megawatt-hours) to Pennsylvania industrial and commercial sector customers, January 1990 through September 2006.

Among nearby states (Kentucky, Maryland, New Jersey, New York, Ohio, and West Virginia), the Commonwealth has the median prices for both commercial and industrial rate classes (see figures 14 and 15, below). The average September 2006 commercial price in the seven states analyzed was 9.75 cents per kilowatt-hour (¢/kWh), 9% above Pennsylvania's price. The average industrial price in the seven states in September was 7.23 ¢/kWh, 12% above Pennsylvania's price. While average prices are useful in understanding competitive positions, a company's decision to expand or relocate considers the rates available to them in a defined location, and may be lower or higher than the average rates. A detailed discussion of the relative rates in the nearby states is provided in section 1.3 below.

Pennsylvania has been holding its competitive position with respect to industrial sales compared to one closely-watched competing state, Kentucky (figure 2) and Pennsylvania has been increasing its substantial lead in commercial sales (figure 3).

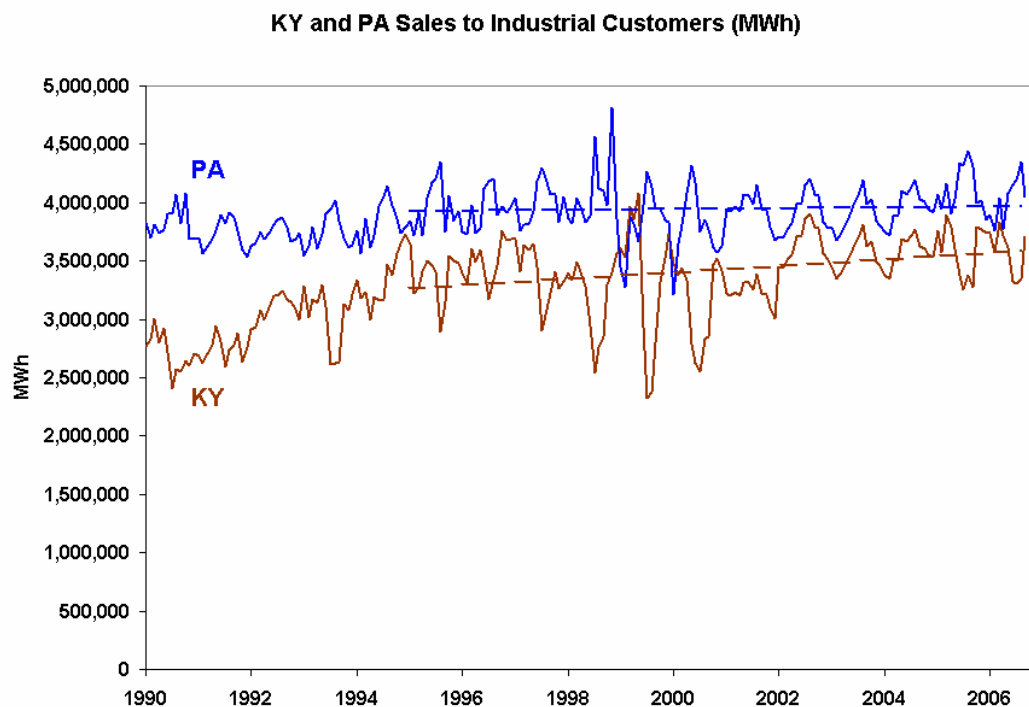


Figure 2. Monthly sales to industrial sector customers in Pennsylvania and Kentucky, 1990-2006.

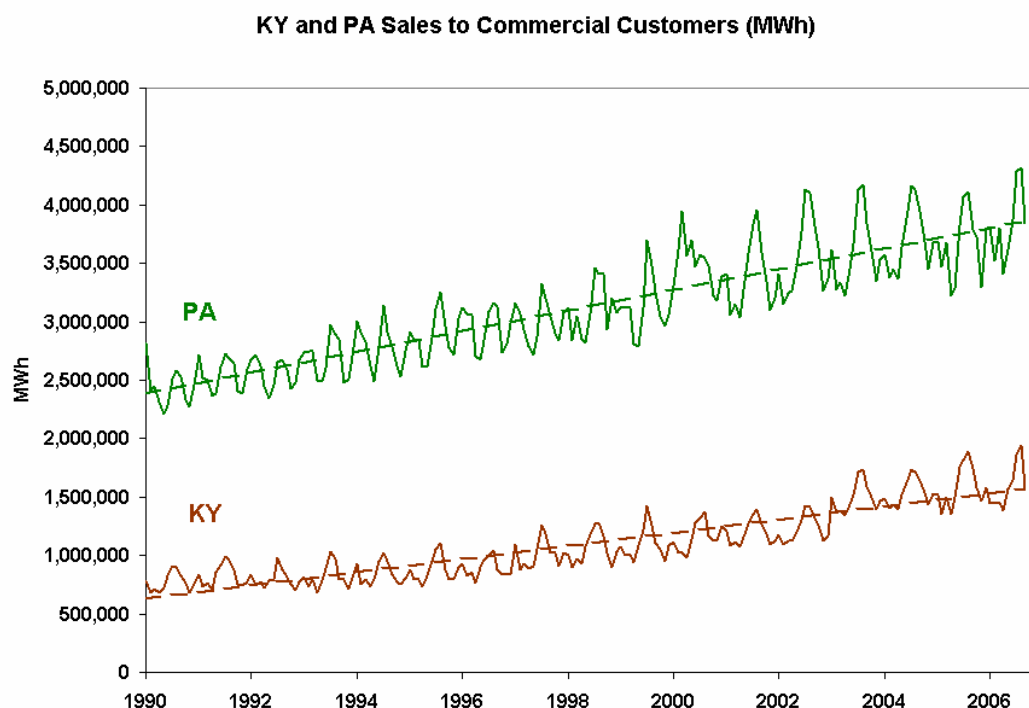


Figure 3. Monthly sales to commercial sector customers in Pennsylvania and Kentucky, 1990-2006.

1.2 Restructuring and Pennsylvania market characteristics

The federal Public Utilities Regulatory Policies Act of 1978 paved the way for unregulated independent power producers (IPPs) to begin operating in the United States. In 1992, Congress expanded the field of eligible entities in the electric power industry with the passage of the Energy Policy Act (EPAct). The EPAct allowed unregulated IPPs to sell power with short- and long-term contracts. In response to an unprecedented rise in electricity prices beginning in 1971 (figure 4), and to the deregulation of other industries, a number of U.S. states enacted legislation to restructure their electricity markets. Restructuring of the electric power industry followed deregulation of natural gas (1978), airlines (1978), railroads (1980), and the trucking industry (1980). Sixteen states currently allow all customers to shop for electricity from suppliers who choose to offer power. Two others allow large customers to choose their suppliers. Figure 5 shows the current status of U.S. electricity restructuring.

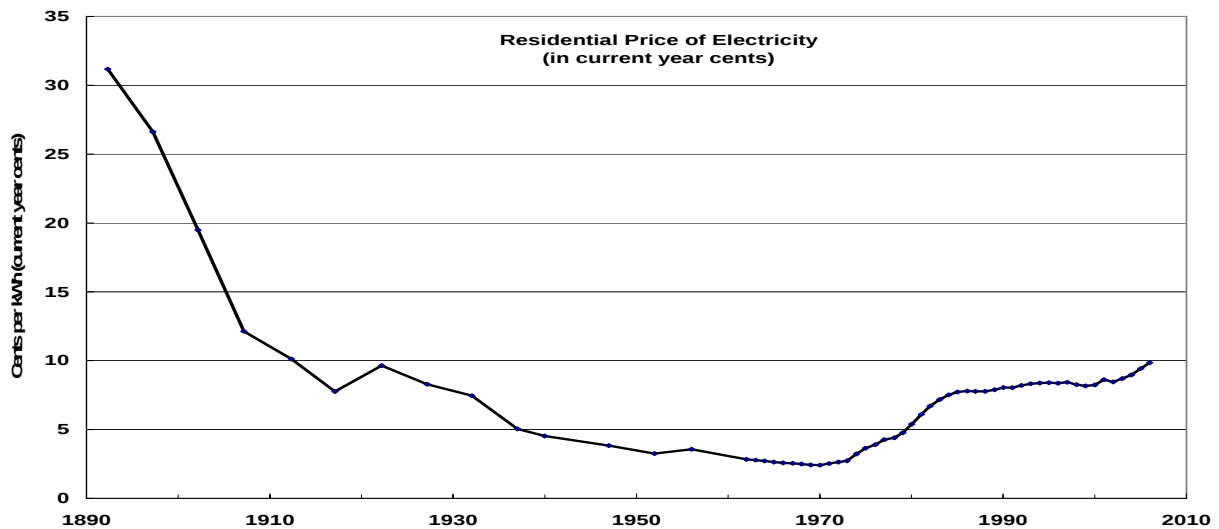


Figure 4. Residential Price of Electricity in the U.S. from 1892 - 2006, in current-year (not inflation-adjusted) cents / kWh. ⁴

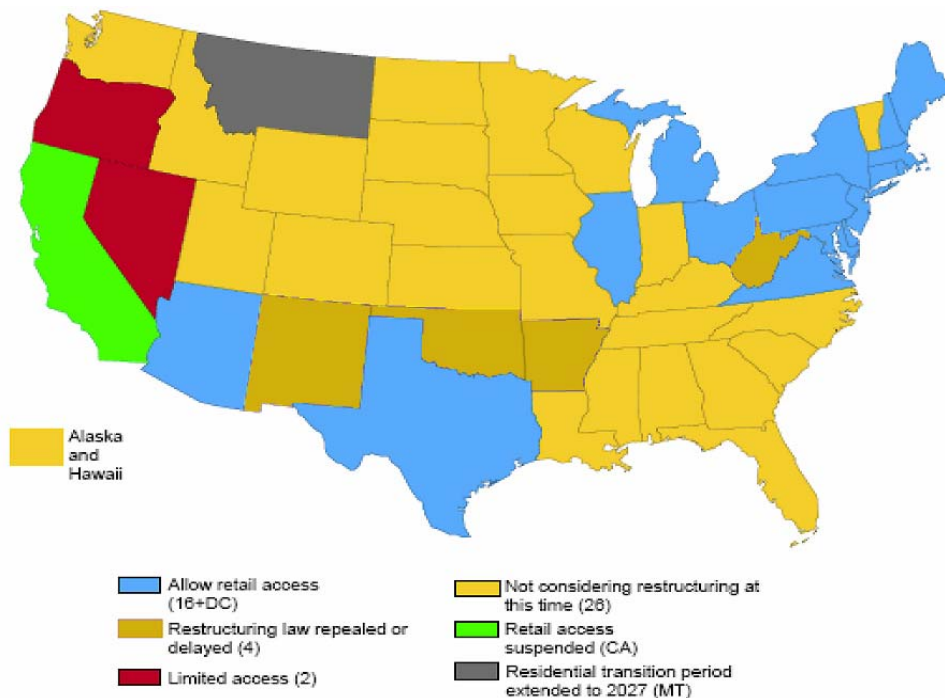


Figure 5. State retail access status, 2006.

Source: "2006 Performance Review of Electric Power Markets" by Kenneth Rose and Karl Meeusen.

In Pennsylvania, the first customers were allowed to select competitive suppliers in 1998. Utilities with assets such as generation plants that had been built under an agreement that their costs were to be amortized over a long period were permitted to recover these “stranded costs” or the difference between sales price and book value through competitive transition charges, and consumers were guaranteed fixed rates. Pennsylvania is unusual among restructured states in that the period of stranded cost recovery and rate freezes differs from utility to utility. Significant extensions have been granted to the rate cap periods beyond the original date of December 31, 2005, and the last expire at the end of 2010. Figure 6 shows the service territories of Pennsylvania’s investor-owned utilities (IOUs), and the Pike County municipal utility. The figure also shows the first full year of un-capped rates in each territory. Some load serving entities have stranded cost recovery plans that provide for rate increases in years leading up to the removal of rate caps. Others will have had no rate changes for twenty years when the rate caps expire.

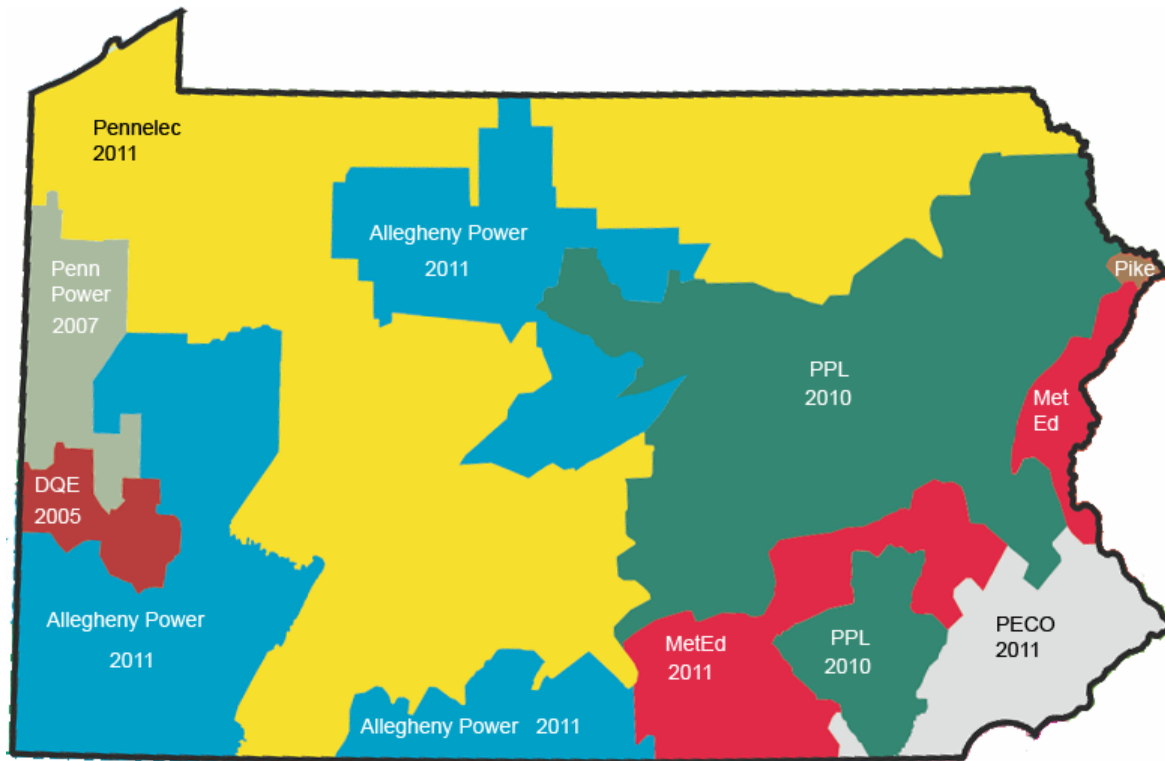


Figure 6. Pennsylvania’s investor-owned utilities and the first full year of un-capped rates for each. FirstEnergy is the parent company for Penn Power, Penelec, and MetEd. Source for base map: PJM 2005 State of the Market Report.

Investor-owned utilities in Pennsylvania were encouraged to divest their generation assets. Some sales were to unregulated subsidiaries, and the rest were to unrelated companies. They reported that at the end of 2005 they owned 6,222 MW of generation capacity. Non-utility generators (sometimes called competitive suppliers) owned 41,657 MW. Co-operative utilities owned 281 MW and publicly-owned power generators 118 MW. Commercial and industrial users generating their own power or power and heat/cooling (sometimes termed customer-generators) owned 1,286 MW of generation capacity.⁵

In order to guarantee universal access to electricity service, Pennsylvania requires the former utility in each service territory to act as a “provider of last resort” (POLR) or “default service provider”. Various rules govern the ability of customers to switch providers. Allowing customers to change providers at any time for any reason promotes competition, but is likely to lead to substantial excess capacity. If a provider prepares to serve a load of a particular size and then finds that many customers have switched to a different provider, it will have incurred costs needlessly. POLR providers build a risk premium into their price to account for this possibility.

The current Pennsylvania rules require each load serving entity (LSE) to supply power to any customer at their POLR rate. POLR rate structures are not identical for all utilities in Pennsylvania. The regulated utility cannot offer a lower price to a customer that is cheaper to serve or insist on a higher price for a customer more expensive to serve. When retail competition began, competitors targeted customers whose volume or use patterns made them low cost customers, leaving the LSE with an increased proportion of higher cost customers. Later, when wholesale generation costs would have forced competitors to set their price above the POLR rate, the competitors discontinued service, throwing their customers back to the LSE. Some customers use the competitors during most of the year when generation costs are low and then return to the LSE when generation costs rise in summer. Both types of switching increase the cost to the LSE, eventually resulting in a higher POLR rate that harms customers, particularly those who do not switch.

POLR providers without enough of their own generation to supply the needs of their customers buy power either via bilateral contracts with generators or via the spot market for power operated by one of the system operators. Non-utility generators buy and sell in both markets. PJM Interconnection, L.L.C. operates the market that covers most of the Commonwealth, with the exception of the Penn Power territory (a member of the Midwest Independent Systems Operator, MISO) and Pike County (a member of the New York Independent Systems Operator, NYISO). PJM is the market maker in the region shown in figure 7. Although there are technical differences, these organizations are termed either regional transmission organizations (RTOs) or independent systems operators (ISOs).

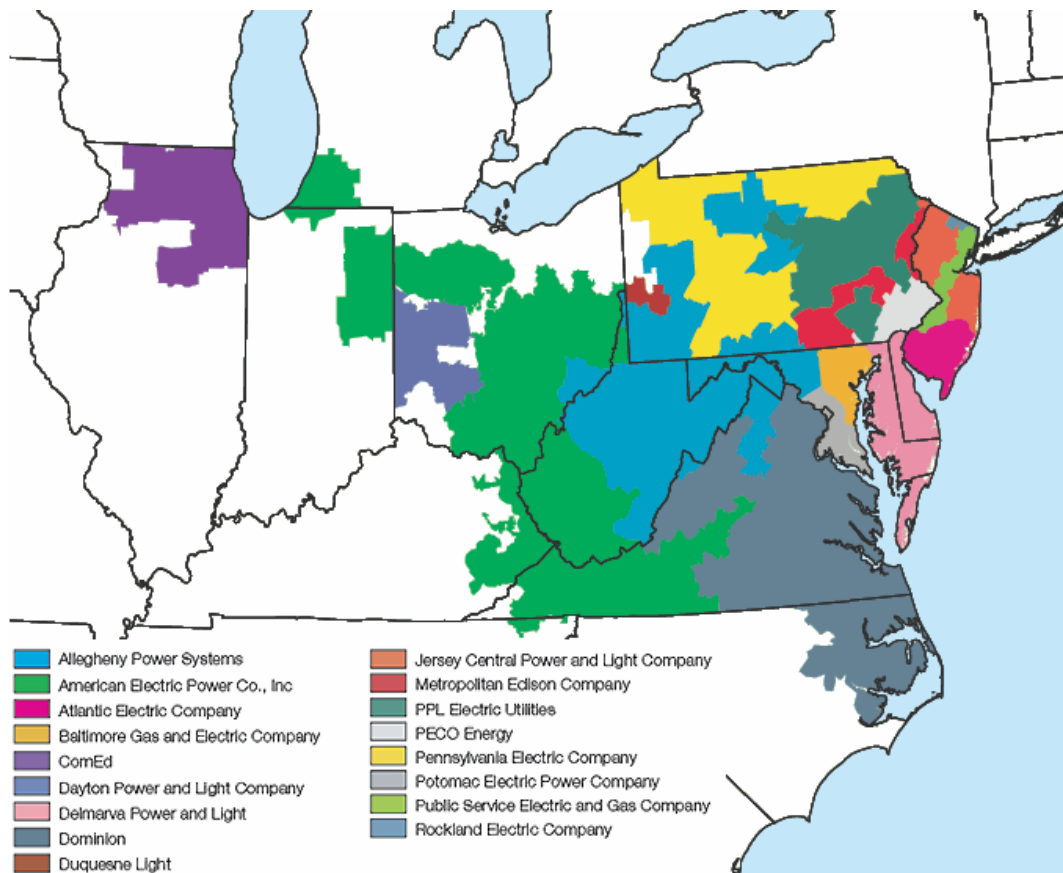


Figure 7. Service territories of load serving entities affiliated with PJM Interconnection, L.L.C.
Source: PJM 2005 State of the Market Report.

Roughly 15 percent of all power sales in the PJM footprint take place in the two PJM markets: a day-ahead spot market, and an hourly spot market.⁶ The remaining 85% of power is sold through bilateral contracts. As in other commodity markets, the spot market price strongly influences the bilateral contract price. While the New York Mercantile Exchange makes a market in monthly PJM electricity futures, few contracts are transacted in the NYMEX futures market, making the prices an unreliable indicator.

Rose and Meeusen report that 11.5% of commercial and industrial load in Pennsylvania in 2006 is served by competitive suppliers.⁷ The majority of that is in Duquesne Light's service territory, with some commercial load in PECO Energy's territory and some industrial load in MetEd/Penelec's area. Considering all restructured states, they conclude, "...the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive marketplace."⁸

Electric generation plants, powered by coal, uranium, water, gas, or oil, supply power to customers through a network of transmission lines. Nationally, since 1982 the transmission grid capacity has not kept up with the increase in electric generation capacity or the number of long-distance wholesale transactions. The most advanced alternating current (AC) transmission lines operate at 765 kilovolts (kV). Higher voltage lines require fewer resources for a given transmission capacity. No lines operating at 765 kV have been constructed in Pennsylvania, although a 765 kV project has been proposed by American Electric Power. The line is likely to relieve some transmission constraints between eastern and western Pennsylvania. AEP estimates that the line will cost \$5.5 million per mile.

Voltage (kV)	Capital cost (\$/mile)	Capacity (MW)	Capital cost (\$/MW-mile)	Corridor width (feet)	Feet / MW
230	480	350	1.37	100	0.29
345	900	900	1.00	125	0.14
500	1200	2000	0.60	175	0.09
765	1800	4000	0.45	200	0.05

Table 3. Typical costs in 2001, thermal capacities, corridor widths, and resource requirements for transmission lines as compiled by Hirst and Kirby. ⁹ Lines in heavily populated regions may be much more costly.

The costs associated with running a generation plant vary, depending on fuel type, engineering and labor efficiency of the plant, capital and maintenance costs, and structure of the plant's financing. If the only plant that can serve a customer is a high-cost unit (for example, an oil or natural gas fueled generator), the customer will pay a high price. If a transmission line is available to bring power from a lower-cost unit (for example, a coal unit) located some distance away, the customer may be able to buy power at a lower rate. However, the existence of the transmission line may raise prices for customers located near the low cost plant, if the price is bid up by customers located at the other end of the transmission line, facing higher cost alternatives.

Equalizing prices between low-cost and high-cost areas is limited by the capacity of the transmission network. If transmission capacity is constrained (the line is then said to be "congested"), then prices in the low-cost and high-cost areas will converge but not equalize.

This concept is responsible for locational price differences in markets such as PJM. Figure 8 shows the real time PJM prices on a day with high, but not record, demand for power. As figure 8 shows, the large demand from Baltimore and Washington bid up spot market prices, since there was insufficient low-cost local generation to supply demand. Where transmission was available to bring power from far-away low-cost areas, prices in those areas were bid up. Low cost generators in West Virginia would like to sell to the Washington area customers, but only a trickle of power can get through the few transmission lines available from West Virginia to Maryland. The grey area of low prices in

northern West Virginia resulted from low cost coal generators with more capacity than was demanded by customers they are able to supply. Even in West Virginia, there were areas of quite high prices near the southwestern population centers, since there is insufficient transmission to equalize prices within the state.

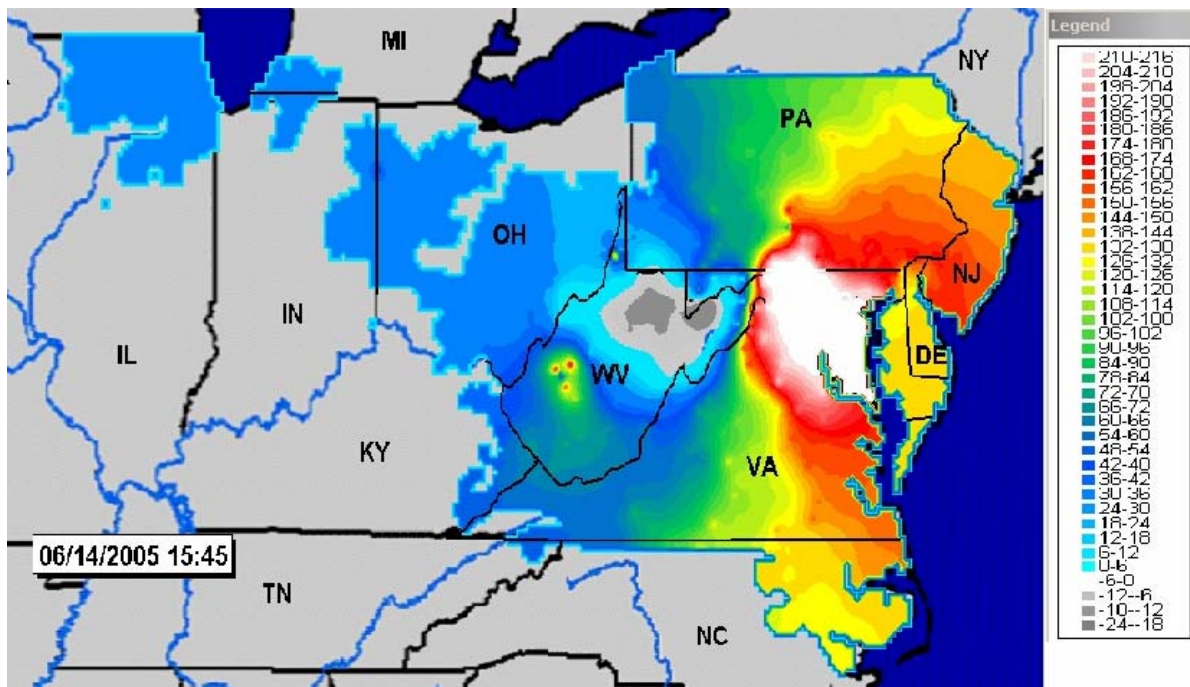


Figure 8. Wholesale prices in dollars per MWh in PJM, June 14, 2005 at 3:45 PM. To obtain prices in cents per kWh, divide these by 10; a price in the deep red of \$180 per MWh is 18 cents per kWh. White represents prices greater than \$216. Source: PJM eTools.

Prices in south central and southeastern Pennsylvania were bid up on that day by local demand and by demand from customers to the east and south. There is insufficient transmission to equalize prices within the Commonwealth, so that prices on that day were lower in Western Pennsylvania, since it has abundant inexpensive coal generation.

Locational prices differences in markets such as PJM are called “congestion charges”. PJM and other RTOs sell financial instruments that can hedge against some or all of these congestion charges. As part of the restructuring agreements, some of these so-called financial transmission rights were allocated to formerly vertically-integrated utilities, now generally POLR providers. Some of these rights are quite valuable on certain days, as they can be used to offset the congestion charges between low-cost and high-demand (and consequently high-price) areas.

Demand for electric power varies with time of day and time of year. Figure 9 illustrates that demand is highest in PJM in the summer months, with a peak in the late afternoon. Winter demand peaks at breakfast time and early evening. Spring and fall demand is lower, and is more uniform from 8 AM to 9 PM than in the other seasons.

Figure 9 shows that demand varies from a low of 60,000 MW in the fall to a high of 135,000 MW in the summer. Generators such as nuclear units, running on average a bit more than 90% of the time, supply power for most of the hours in a year. Some coal units operate 80% of the time. Both are called “baseload units”. In order to meet the demand for power during the day, additional units are brought on line. These are generally termed “shoulder units”. To meet demand in the peak hours of the summer or winter, “peaking units” are used. Some of these are run only a few times a year when demand is very high.

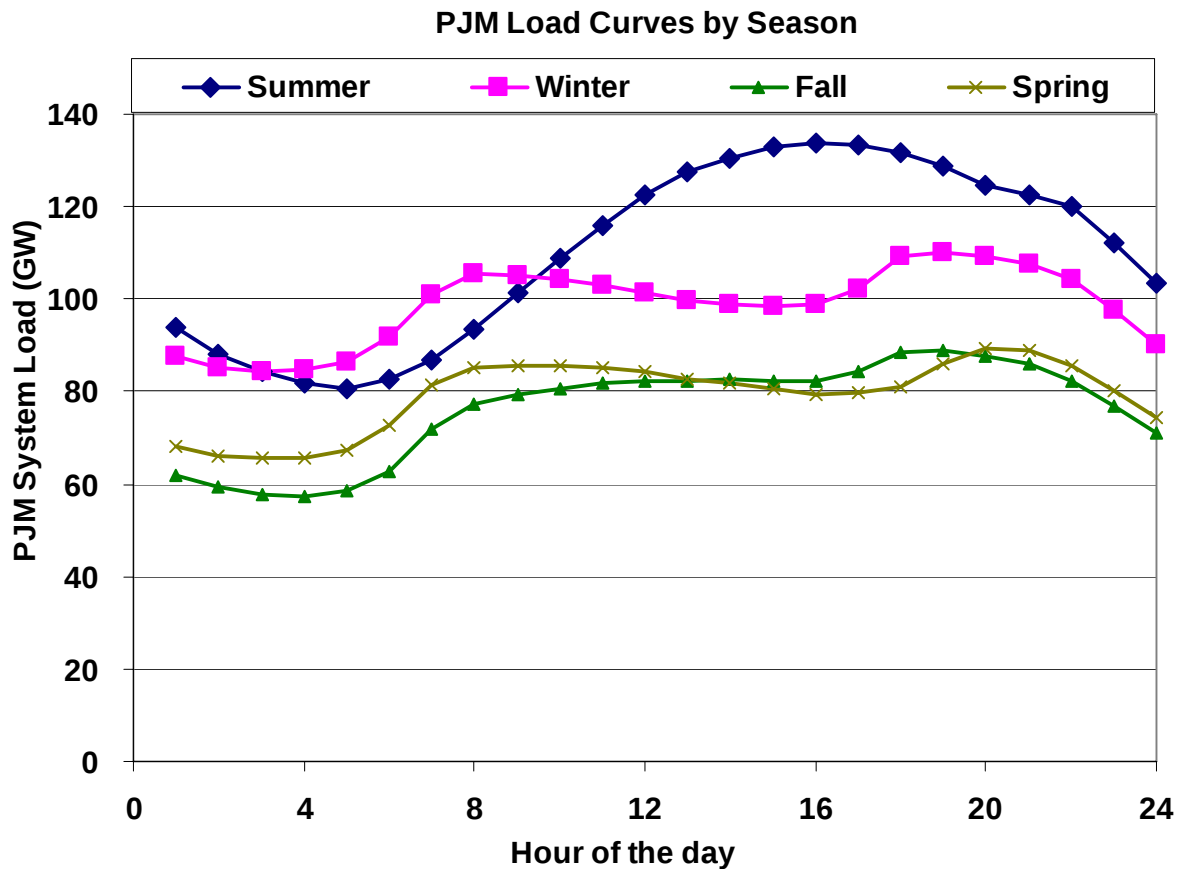


Figure 9. Demand for electricity in PJM, thousands of MW on one day in each season over the past year.
Source: PJM eTools

The day ahead and real time spot markets are managed by the Regional Transmission Organization (for example, PJM). It accepts bids from generators to supply a predetermined amount of load. The winning bids are accepted in order, starting with the lowest bid. The RTO determines the “market clearing price” as the bid of the last generator needed to meet expected demand. All bidders are paid the market clearing price, plus adjustments (which may be positive or negative) to reflect congestion in the transmission network.

In a regulated market, the public utility commission allows the utility to recover its costs plus a return on investment (currently 9.5% to 11.6%, depending on the utility and state¹⁰) The average cost of generation in regulated states is a weighted average of the costs (capital and operating) for all baseload, shoulder, and peaking units. The costs include paying off the investment with a rate of return. The total expense (price times quantity) paid by consumers is shown in the cross-hatched area of figure 10a.

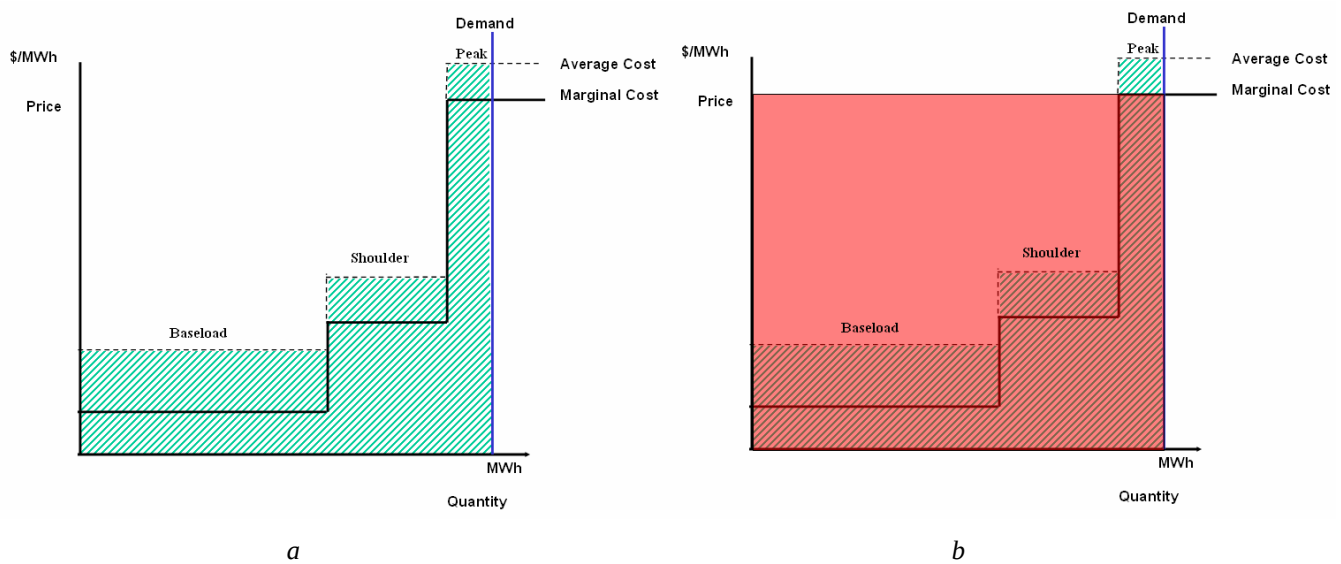


Figure 10. Average cost (comprised of capital and operating costs) and marginal cost (only the variable operating cost) for baseload, shoulder, and peak generating units. Under a regulated utility model, the utility is paid the cross-hatched area, plus a fixed return on invested capital (a). Under a uniform price auction in a competitive market, the total price paid by consumers is the colored rectangle in (b).

In a restructured market, the power that is transacted in the day-ahead and hourly spot markets (approximately 15% of the total power in PJM) is paid a uniform price, set by the bid of the highest cost generator whose power is required to meet demand in that hour. Bi-lateral contracts tend to reflect the spot market price. In a competitive market, the bids received will reflect marginal cost (just the fuel and labor costs of running the generator for that hour, not including the capital expenses), which is lower than the average cost (marginal cost plus capital costs). The uniform price auction means that baseload and shoulder units are paid more than marginal cost in hours when peak units are required. During hours of peak demand, the baseload units will be paid more than their average cost. The total expense (price times quantity) paid by consumers is shown in the colored area of figure 10b. The figures are for a period of high demand and show that the baseload and shoulder generators are paid more than their marginal or average costs in the auction. During high demand periods, customers pay more during the auction than they do under the regulated structure.

In a pay-as-bid auction, each successful bidder is paid their bid, rather than a uniform market-clearing price; this might seem better for consumers than a uniform price auction. However, each generation owner knows the costs of all generators as well as which ones are in service; since PJM specifies the quantity of electricity they want to buy, each owner can estimate the market clearing price. Under these conditions, all low-cost generation owners would bid this market clearing price rather than their marginal cost, meaning that the pay as bid system would result in the same price as paying the market clearing price. Since auctions are held each hour (8760 times per year), bidders learn strategy quickly and a pay-as-bid auction leads to the same or higher price than a uniform price auction.

Deregulation advocates assume that paying all generators the market clearing price will result in paying generators less than if each unit were paid its average cost. They also assume that unneeded and high-cost capacity would be eliminated in a competitive market. The assumption is equivalent to believing that the average market clearing price over a year will be less than the weighted average unit costs of all generators. The experience of deregulated states does not show that this has actually occurred. If average price did fall, unless costs fell more due to eliminating unneeded capacity, high-cost plants, and greater efficiency, deregulation would lead to insufficient capacity because investors didn't receive attractive profit levels. In particular, a competitive market is likely to over-pay baseload generators on average but never allow the highest cost generators to earn their fixed costs. Therefore, a

competitive electricity market would leave the system short of capacity, unless some other mechanism, such as a capacity payment were used. Thus, the justification for competition relies on the assumption that it will force plants to lower their costs, force high-cost plants out of business, and eliminate excess capacity.

The prices in the day-ahead and real time hourly PJM markets vary by time of day, driven by demand and the costs of units used to meet that demand. The average prices in each market for 2005 are shown in figure 11.

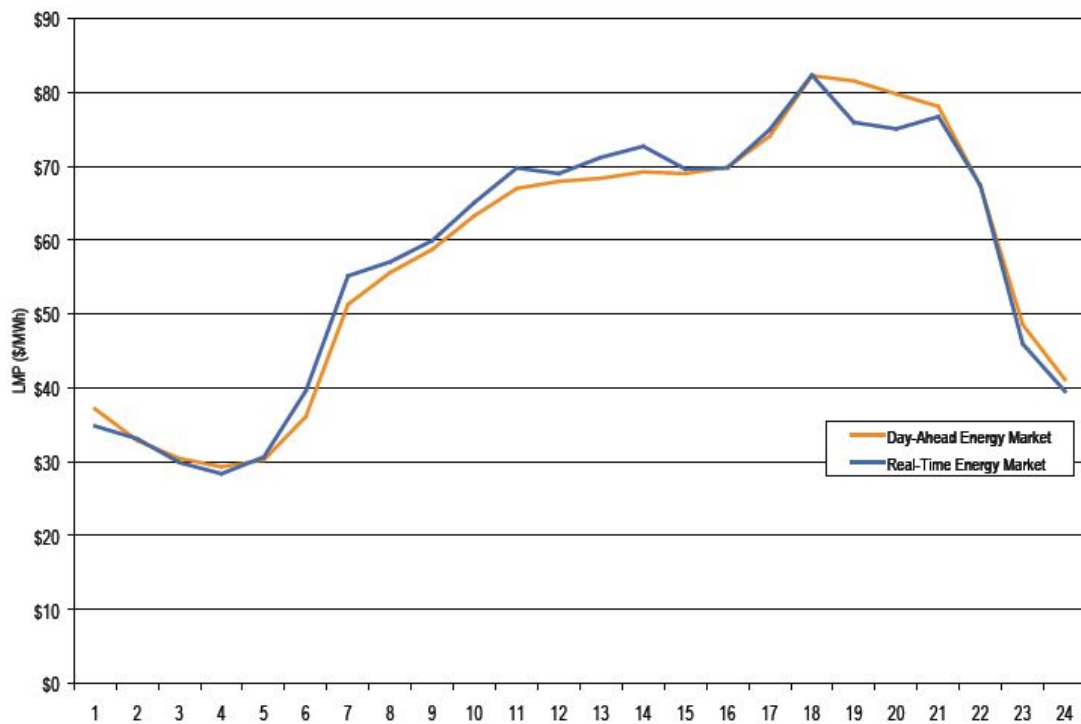


Figure 11. Average price in the PJM markets by time of day for the year 2005. Source: PJM 2005 State of the Market Report.

Average price data do not capture the volatile character of the market on low-demand days when supply far exceeds demand or on days when high demand causes very high cost units to be run for a few hours. Figure 12 shows that in 10% of the hours in 2005, wholesale prices exceeded 10 cents per kWh (\$100 per MWh).

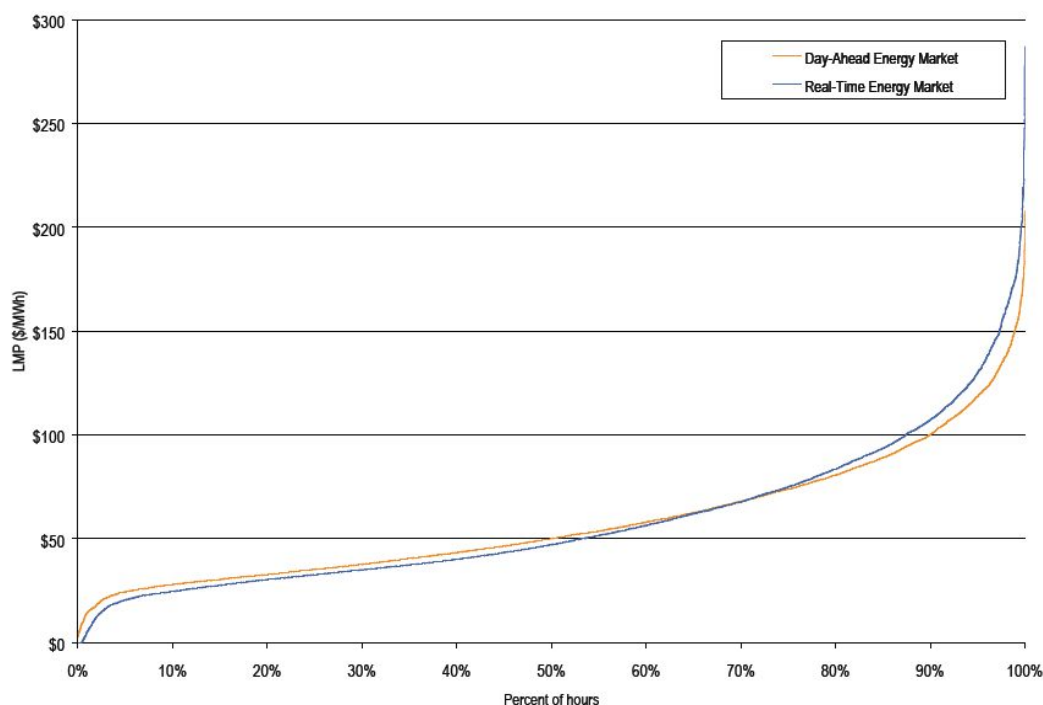


Figure 12. Price duration curve for the 2005 PJM day-ahead and real time markets.
Source: PJM 2005 State of the Market Report.

The capital, maintenance, and operating (including fuel) cost of a generator affects its market bids and hence how frequently it is used. There is a substantial difference between the installed capacity and the capacity used most-intensively to actually generate electricity. Figure 13a shows the PJM installed capacity in MW by fuel type. Figure 13b shows the capacity as actually used during 2005.

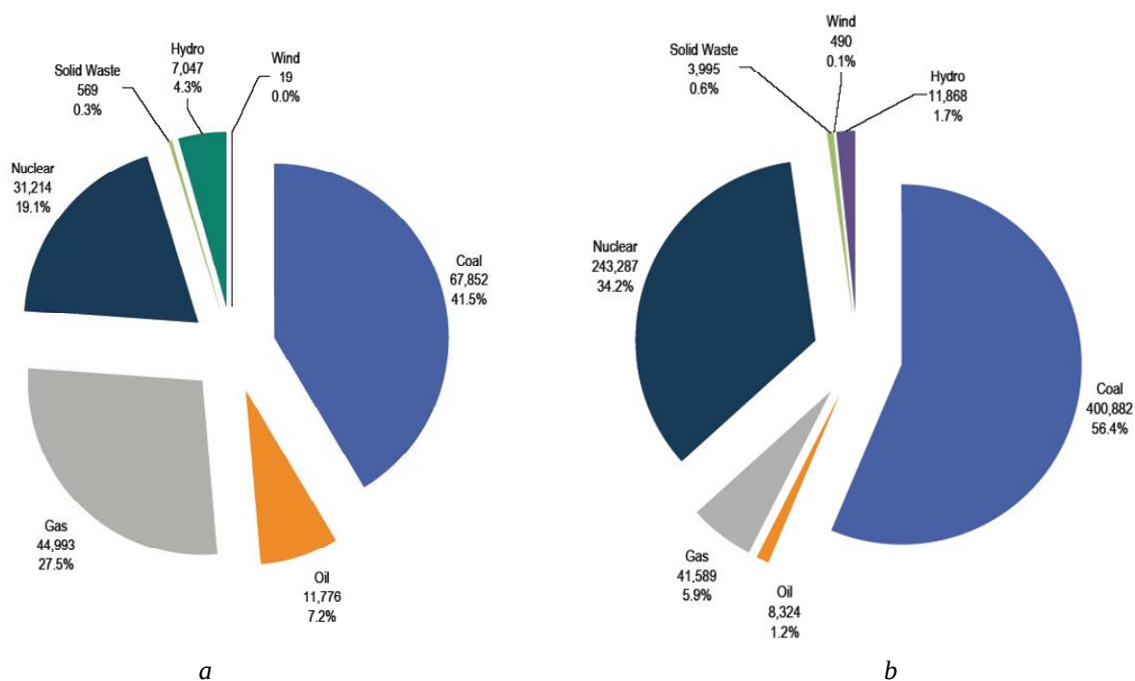


Figure 13. PJM installed capacity in MW (a) and dispatched generation fuel mix (in MWh) during 2005 (b).¹¹

In addition to the requirement for energy, electricity system operators must provide a number of what are termed “ancillary services”. These are the services required to have the system deliver high quality power reliably, include maintaining the system frequency at 60 Hertz (60 cycles per second), providing reserve generating capability available on very short notice should an in-service generator suffer a failure, and providing day-to-day reserve capacity to meet swings in demand.

1.3 Market expectations and performance

Before restructuring got underway, microeconomic studies indicated that efficiency gains of 3 to 13% were feasible through competitive pressures.^{12, 13} One study of generators¹⁴ indicates that employment has dropped 29% in restructured states and 19% in other states since the peak in 1991. If correct, that 10% difference would have lowered cost by only roughly 0.7%, since labor costs represent about 7% of electricity cost.

The record on overall operations costs and thermal efficiencies is mixed, although the evidence suggests that operating efficiency has increased for low-cost generating facilities such as nuclear and coal units.¹⁵ A review of electricity prices in all states conducted for the Virginia State Corporation Commission in August 2006 concludes, “The evidence suggests that, at least so far, no discernable benefit can be seen for customers in restructured states once the rate caps have expired. Increasingly the evidence is beginning to now suggest that prices for customers in restructured states may actually be increasing faster than for customers in states that did not restructure.”¹⁶

The primary impetus for electricity reform was cost. It is not surprising that California and Pennsylvania were the pioneers of electricity deregulation, since they had electricity prices 45% and 20% above the national average in 1992 when the federal Energy Policy Act opened the door to restructuring. The Federal Reserve Bank of New York predicted in 2000 that “... the market forces introduced to the industry by deregulation should cause electricity rates to drop below the levels that would have prevailed under a monopoly system.”¹⁷

In New Jersey the end of price caps in 2003 was followed by a 19% rate increase. In Maryland, the end of rate caps was followed by rate increases; the largest was for customers of Baltimore Gas and Electric, which saw its overall rate increase by 72% (while the legislature has allowed these increases to be spread over several years, customers pay a surcharge for the cost of the deferral).

In Pike County, Pennsylvania, commercial and industrial customers of the small Pike County Light & Power Company saw increases of 85% after the lifting of rate caps.¹⁸ The Maryland and Pike County increases have caused considerable concern that the expiration of rate caps in the rest of Pennsylvania will result in similarly dramatic price increases.

In areas of Pennsylvania where the rate caps have been lifted, it is possible to look at results for commercial and industrial customers. In anticipation of competition lowering prices in Pennsylvania, customers and suppliers struck deals for contracts with terms from three to ten years beginning in 1997, generally at prices below prevailing rates at the time. A typical large customer was offered a five-year contract at a rate 15% below what they had been paying. When these contracts expired, the customers reverted to rates roughly equal to what they had been paying in the regulated era, representing a 15% increase. Many of these customers worry that further rate increases are imminent. Data compiled by the Industrial Energy Consumers of Pennsylvania indicates that load serving entities in the Commonwealth expect increases in rates from 30 to 75 percent. The Pennsylvania Office of the Small Business Advocate reports commercial customers have similar expectations.

Some commercial customers reported in our interviews that they are very pleased with the results of restructuring, although all reported that their rates have increased since restructuring. Both large

educational institutions and big-box retailers report that they have signed contracts (generally of one year duration) with competitive suppliers at rates as low as 36% below the POLR rates for commercial customers.

Comparisons of the most recent available commercial and industrial prices for Pennsylvania and nearby states are given in figures 14 and 15. The data are from the U.S. Energy Information Administration.¹⁹ The time history of the commercial and industrial prices is given in figures 16 and 17 for the seven states for the period 1990 through 2006 as a 12-month centered average to reduce seasonal effects.

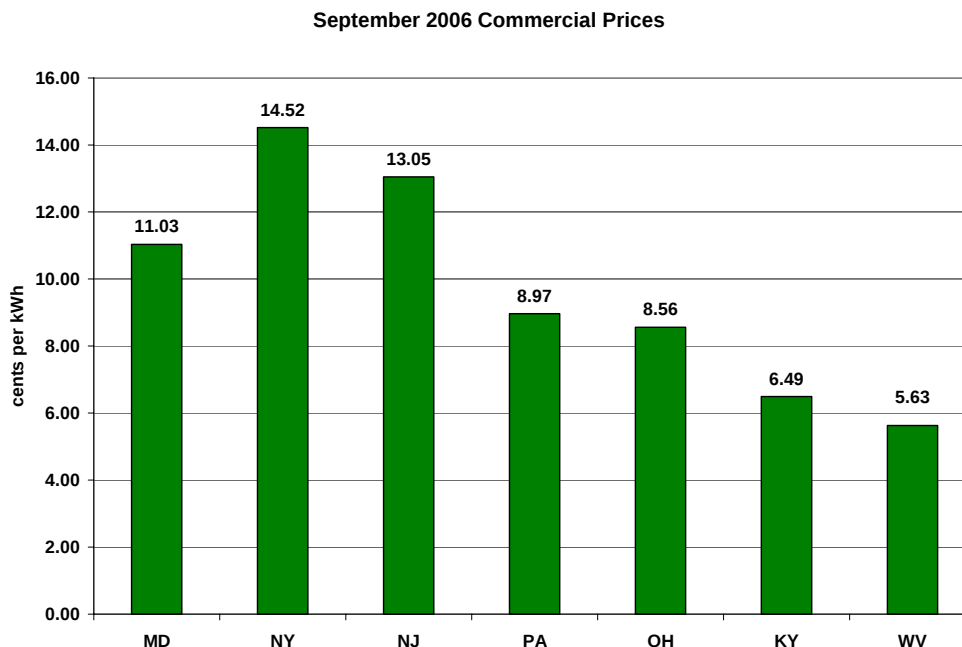


Figure 14. Average electricity prices for the commercial sector in September 2006.

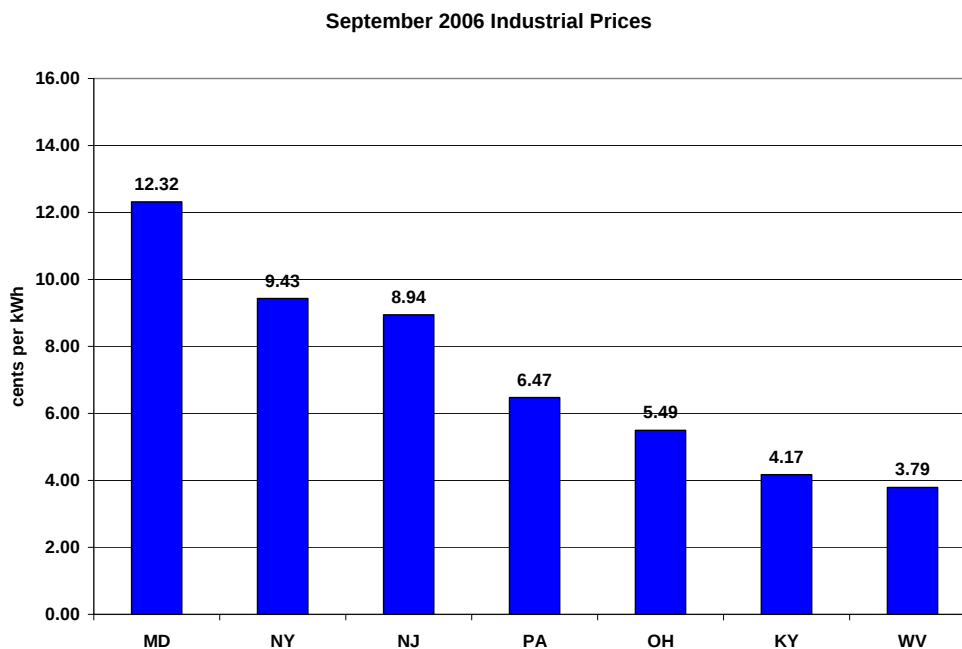


Figure 15. Average electricity prices for the industrial sector in September 2006.

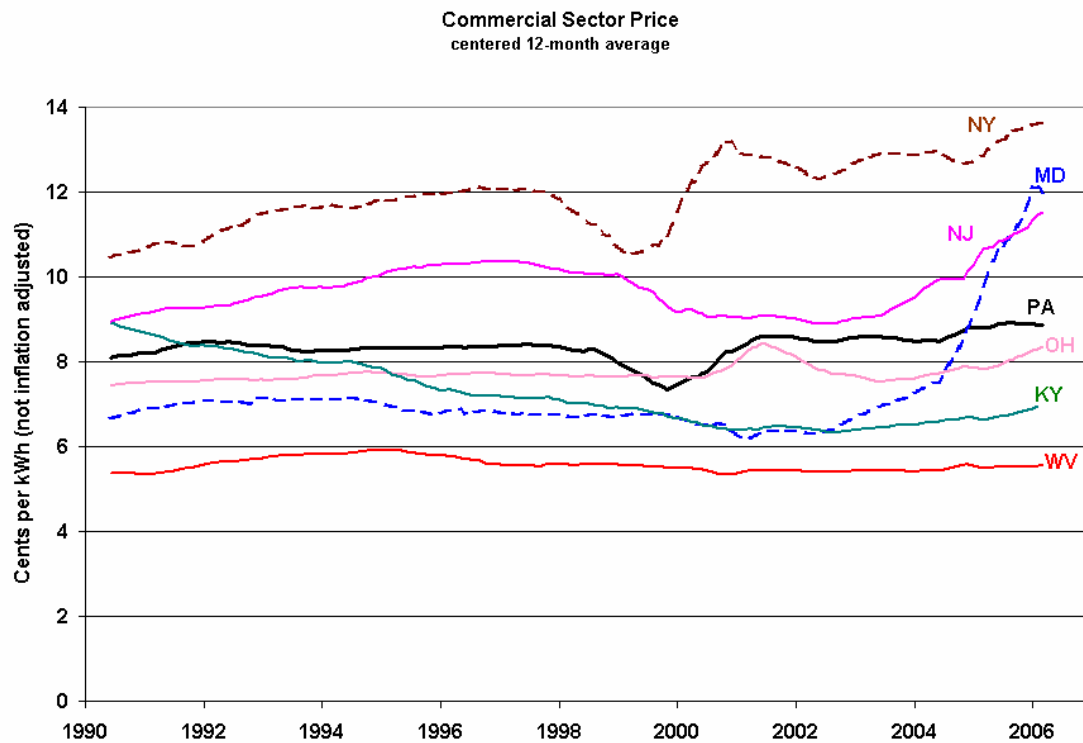


Figure 16. Average electricity prices for the commercial sector from 1990 to 2006. Seasonal periodicity has been reduced by taking a 12-month centered average of the data.

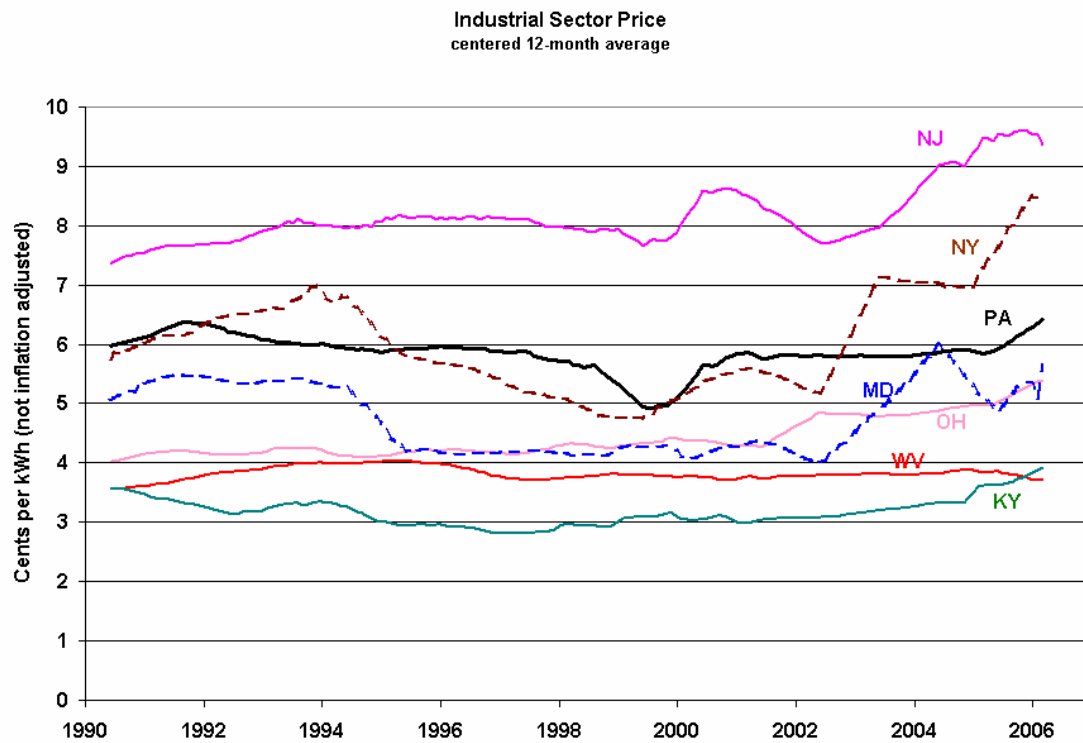


Figure 17. Average electricity prices for the industrial sector from 1990 to 2006. Seasonal periodicity has been reduced by taking a 12-month centered average of the data.

Pennsylvania's competitive position with respect to nearby states currently places the Commonwealth at the median of prices for both commercial and industrial rate classes. The average September 2006 commercial price in Pennsylvania and the six nearby states shown in figures 14 through 17 was 9.75 cents per kilowatt-hour (¢/kWh), 9% above Pennsylvania's price. The mean industrial price in these seven states in September was 7.23 ¢/kWh, 12% above Pennsylvania's price. For the 12 month average ending in September 2006, Pennsylvania was the median state for commercial rates, and the third-highest state for industrial rates (table 4). The difference is due to large variability in Maryland's industrial rates over the past year. However, a commercial or industrial electricity user finds no comfort in the comparison of median prices. They are concerned about the price they will be charged and compare it to the price they could expect to pay in other states in which they may locate.

	<u>September, 2006</u>			<u>12-month trailing average</u>		
	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>
U.S. mean	10.94	9.78	6.27	10.21	9.24	6.00
Kentucky	7.36	6.49	4.17	6.90	6.27	3.92
Maryland	10.92	11.03	12.32	9.02	11.98	5.65
New Jersey	13.89	13.05	8.94	12.31	11.52	9.35
New York	17.89	14.52	9.43	16.84	13.61	8.50
Ohio	10.00	8.56	5.49	9.23	8.35	5.40
Pennsylvania	10.64	8.97	6.47	10.35	8.88	6.41
West Virginia	6.74	5.63	3.79	6.33	5.56	3.71
7-state median	10.64	8.97	6.47	9.23	8.88	5.65
7-state mean	11.06	9.75	7.23	10.14	9.45	6.13
Pennsylvania / 7-state mean	96%	92%	89%	102%	94%	104%

*Table 4. Average price paid in each rate class in the U.S., Pennsylvania and nearby states, in cents per kWh.
Source: U.S. Energy Information Administration.²*

The degree to which Pennsylvania's electricity prices (compared to other states) affects the business environment in the Commonwealth varies among sectors and among companies. In public forums, U.S. Steel has stated that Pennsylvania is the most expensive state for electricity of those in which they operate (the others are Ohio, Michigan, Indiana, Minnesota, Illinois, and Alabama). Also in a public forum, Allegheny Technologies has stated that they are at a disadvantage amounting to \$20 million yearly with respect to North American Stainless, their competitor in Kentucky. Commercial and industrial customers interviewed for this study stated that Pennsylvania electric rates they paid were lower than in New England, New Jersey, northern Ohio, and Maryland. States mentioned as having lower rates than Pennsylvania in the interviews included southern Ohio, Kentucky, Texas, and Alabama. A number of industrial customers stated that natural gas, not electricity was their largest energy cost. Commercial firms in general stated that labor considerations (workforce availability) was the most important factor influencing their location decisions.

We anticipate that a number of factors will alter the competitive position of each state. For the low price states of Kentucky and West Virginia, the Clean Air Interstate Rule (CAIR) regulation of oxides of nitrogen and sulfur is likely to add approximately 0.9 cents per kilowatt-hour to their wholesale cost, since the two are overwhelmingly coal generation states. If mercury control is mandated in these states, their cost of generation is likely to rise by a further 0.2 cents per kWh. Both states have provisions for fuel and environmental cost escalation to be passed through to customers. In December 2006, the Kentucky Public Service Commission approved for Duke Energy customers a 21-percent commercial and industrial rate increase and the resumption of the utility's monthly fuel cost adjustments

in March. Also approved were new environmental controls for Louisville Gas & Electric and Kentucky Utilities.

New transmission lines could cause electricity in West Virginia to be cheaper than that in Maryland by only the cost of transmission. If the new line from Ohio to New Jersey currently proposed by American Electric Power is completed, prices in southern Ohio (where U.S. Steel's plant is located) will converge toward those in New Jersey, subject to the limited capacity of the transmission line and transmission costs. Within Ohio, prices will tend to equalize between the expensive north and the inexpensive south. If economic development agencies in West Virginia, Kentucky, and Southern Ohio want to maintain lower electricity prices than Pennsylvania as new transmission is built (aside from transmission costs), they would have to subsidize industrial and commercial customers from other ratepayers or from the state treasury.

2. REVIEW OF PREVIOUSLY IDENTIFIED POLICY OPTIONS

2.1 Prior reports

Whether restructuring and the introduction of centralized regional wholesale electric markets has brought benefits (and in what form) is a contentious subject. Many studies have been done by consultants and university researchers. There is no doubt that restructuring caused a debacle in California in 2000, but there is little agreement beyond that. Restructuring has been a broad and drawn-out process that inevitably is difficult to treat statistically. Two recent reviews of the literature on restructuring conclude that the statistical problems are sufficiently challenging that no definitive study exists on the benefits or costs of restructuring.²⁰ Most of the existing studies focus on regional wholesale markets and not on specific states; thus, there may be limited insight for Pennsylvania from these studies. Further, the quantitative price studies are focused solely on determining whether restructuring has had an effect on retail electricity prices for various customer classes; they do not contain substantive discussion of possible remedies for higher prices.

This section discusses three studies whose results offer the most insights into policy options that Pennsylvania might pursue to mitigate the effects of rising electricity prices. The first is a report commissioned by the Allegheny Conference on Economic Development; it attempts to address many of the same issues as this report, but with a focus on Western Pennsylvania. The second, from the Industrial Energy Consumers of Pennsylvania, is not a quantitative study of price but rather contains a discussion of policy options most likely to affect the industrial rate class. The third, from Energy Security Analysis, Incorporated, focuses on price effects in the PJM wholesale market. This study does not offer any concrete policy suggestions but is discussed here since it is the only study that has a locational component to its pricing discussion.

2.1.1 The Allegheny Conference on Community Development report

In 2005, the Carnegie Mellon Electricity Industry Center was asked by the Allegheny Conference on Economic Development to assess the electricity market faced by large industrial customers in Western Pennsylvania.²¹ The report describes the influence of the retail electricity market on the decisions of large industrial customers to locate, relocate, or expand in Western Pennsylvania. The report focuses specifically on competition for jobs between Western Pennsylvania and nearby states with lower electricity costs (and that have not made the transition to retail electric competition), such as West Virginia and Kentucky. It also discusses several policy options that could be pursued at the state or local level to reduce the cost of electricity to industrial customers in Western Pennsylvania.

Although the Allegheny Conference report focuses exclusively on Western Pennsylvania (with a particular focus on Allegheny County), it provides the most thorough discussion to date of issues with electricity competition specific to Pennsylvania and large industrial users.

The Allegheny Conference report detailed the various components of a typical electric bill for a Western Pennsylvania industrial customer, reproduced here as table 5.

<u>Charge</u>	<u>cents per kWh</u>	
Transmission loss charge	0.05	
Transmission charge	0.21	
Voltage and frequency regulation	0.19	
PJM grid management charge	0.07	
PJM seams elimination charge	0.05	(expires in 2006)
Capacity payments	0.10	
Load shaping adder	0.40	
Gross Receipts Tax	0.43	

*Table 5. Electric bill for an industrial customer in Western Pennsylvania.
Source: Allegheny Conference report, based on data from Duquesne Light.*

The first three charges apply to every electric system in the U.S. Insofar as a restructured market requires more generation in order to connect a range of competitive supplies to each customer, the two transmission charges will be higher. The remaining charges come either from PJM or the Commonwealth. These charges amount to 1.05 cents per kWh, or about 1/6 of the average locational marginal price (LMP) in the PJM system.²² The Allegheny Conference report suggests that eliminating both the Commonwealth Gross Receipts Tax and the load-shaping adder could reduce electricity costs substantially. Table 5 represents a useful breakdown of the electric bill for policy purposes, but there appear to have been some important changes to the cost structure of providing electricity to industrial customers in Pennsylvania since the date of the report. While the Commonwealth still assesses the Gross Receipts Tax on electricity produced in Pennsylvania, our review of current utility tariffs (as well as the PJM tariff) found no mention of the load shaping adder.

The Allegheny Conference report mentions that distribution utilities are prohibited from offering long-term default service following the expiration of generation rate caps. The report recommended lifting the restriction as a way to reduce price volatility and reduce rates for industrial customers. The Pennsylvania P.U.C. explicitly denied the request of Duquesne Light to offer long-term default service,²³ on the grounds that it would inhibit the development of retail electric competition. Despite this ruling, there has been no explicit statewide prohibition against long-term default service contracts, and certain members of the P.U.C. have shown some willingness to revisit the issue.²⁴

The Allegheny Conference report also notes that the Commonwealth could use its favorable credit rating either to finance or build public power projects earmarked towards specific customers or rate classes (similar to the Power for Jobs program run by the New York Power Authority). While the investment community does tend to offer much more favorable financing to municipal entities than to other market participants (such as non-utility generators), placing the risk of cost overruns or operational problems on taxpayers is not a risk-free strategy. In particular, if the state signs long-term contracts covering several years or even decades, and the earmarked customers do not require power for that long, the Commonwealth could find itself in a similar excess-capacity situation as the Western Pennsylvania utilities found themselves following the decline of the steel industry. If the Commonwealth were forced to shut down publicly-funded plants or sell into the PJM market at below-contract prices, the state's taxpayers and credit rating could suffer.

2.1.2 The IECPA report

The IECPA report evaluates several alternatives directed towards the industrial sector. These policy options include:

- Extension of rate caps;
- Establish a “rate stabilization period” following the removal of rate caps;
- Economic development electric rates for industrials, with the subsidy paid for either through taxes, surcharges on other customers, or POLR suppliers;
- Measures to increase participation in PJM’s demand response programs;
- Requirements to sell alternative-energy credits at cost to industrial customers;
- Lobbying opposition against some or all of the Pennsylvania alternative energy requirements;
- Specific tax breaks for industrial customers;
- Taxes targeted towards competitive suppliers, with the proceeds used to subsidize industrial rates;
- Ordering rebates to consumers when market prices exceed costs;
- Establishment of a public power authority or other public agency through which power plants can be financed or construction (likely under the condition that the power is sold at cost).

In general, the policy suggestions in the IECPA report mirror those that IECPA submitted to the Pennsylvania P.U.C. under their investigation of policies to mitigate electricity price increases.²⁵ The IECPA report does not attempt to estimate the costs or likely effectiveness of any of these proposed policies. The policy alternatives contained in the IECPA report should thus be viewed as targeted towards the industrial customer class. The IECPA report is aimed explicitly at lowering electricity prices for industrial customers; the policy suggestions are made without regard to economic efficiency or effects on other rate classes or the Commonwealth as a whole.

2.1.3 The ESAI report

Beginning in 2002, PJM began expanding its traditional footprint when Allegheny Power joined the PJM regional transmission organization (RTO). Since then, PJM’s territory has expanded (though non-contiguously) as far west as Chicago. Energy Security Analysis, Incorporated (ESAI) has issued a report detailing the effects of PJM’s market expansion.²⁶ While the report focuses only on the wholesale market, and does not provide any policy insights specific to Pennsylvania, one of the apparent goals of Pennsylvania’s Competition Act was to link retail prices more closely with those prevailing in the wholesale market.²⁷ Thus, technical or regulatory changes affecting the wholesale market are significant in evaluating the effects on retail electricity pricing in general, and the competitive climate for commercial and industrial rate classes specifically in Pennsylvania.

The ESAI report uses power-flow modeling techniques to analyze the effects of PJM’s market expansion on LMPs throughout the PJM footprint. The expansion of PJM has incorporated a great deal of inexpensive coal generation into PJM’s dispatch stack. In principle, this could have the effect of lowering prices throughout PJM, as less costly generation is more heavily utilized. The value of the ESAI study is to explicitly incorporate some of the transmission-network effects that may prevent inexpensive generation sources from being most-efficiently utilized.

Figures 18 and 19 show a contour plot of simulated LMPs before and after PJM's grid integration. In figure 18, the largest LMPs are on the eastern side of known transmission constraints, while the LMPs in Western PJM are much lower.

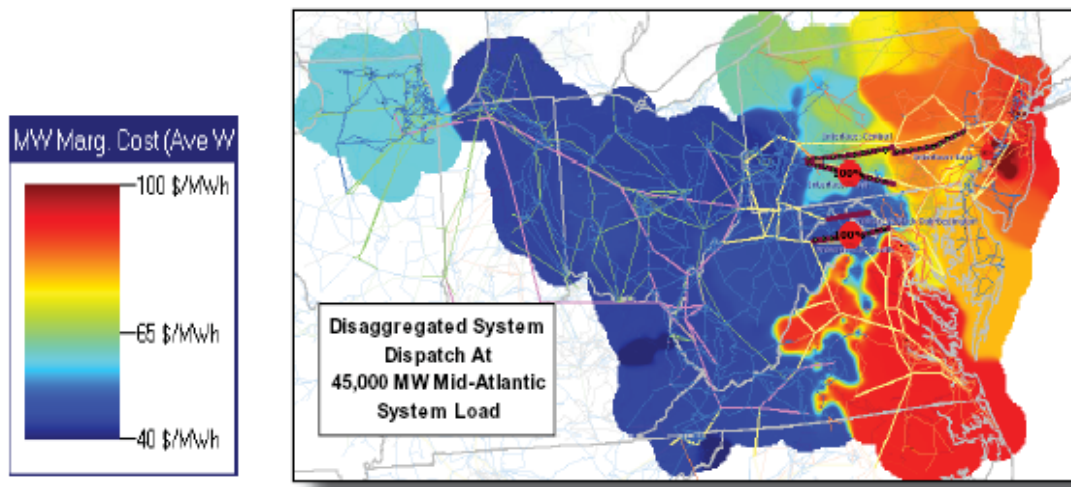


Figure 18. LMP contour map prior to PJM westward expansion. Source: ESAI.

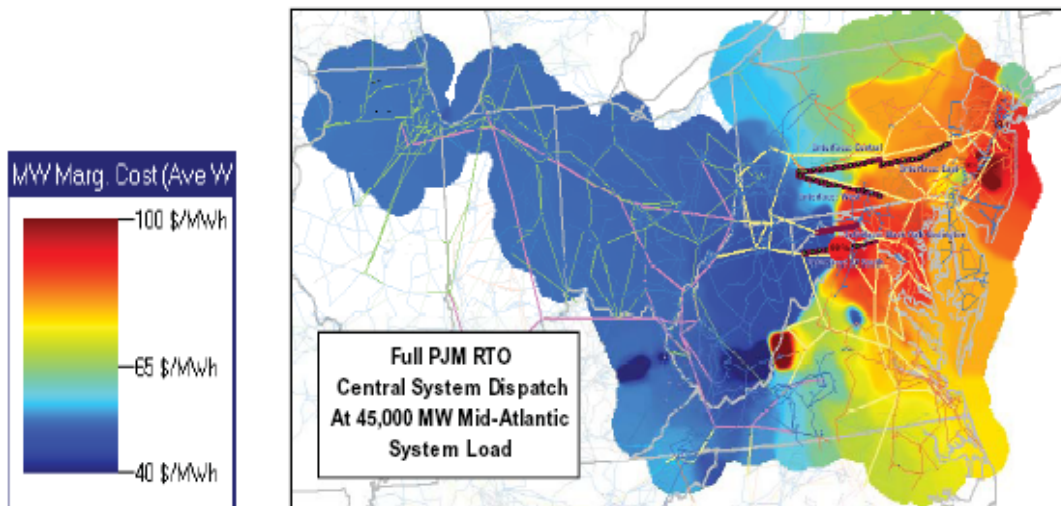


Figure 19. LMP contour map following PJM westward expansion. Source: ESAI.

Figure 19 shows that optimization of generation resources in the larger PJM system does have the effect of decreasing LMPs in some regions of eastern PJM (although some areas such as Philadelphia and New Jersey, see little if any price relief). LMPs in Western PJM and in particular Western Pennsylvania, have increased following the expansion of PJM. None of the market fundamentals (such as load and generation) are different before and after PJM's territorial expansion. The reason for the price increases in Western Pennsylvania mirrors the discussion in Section 1.2 surrounding figure 8. When low-cost resources such as those in Western Pennsylvania are dispatched to serve high-cost load in Eastern Pennsylvania and surrounding areas, the increased demand for low-cost resources increases bids for these resources.

2.2 Pennsylvania P.U.C. hearing on electricity price increases

On May 19, 2006, the Pennsylvania Public Utility Commission instigated an investigation into the potential for large electricity price increases following the lifting of generation rate caps.²⁸ Customers of Pennsylvania Power and Light (PPL) will see their generation rate caps expire at the end of 2009, while customers of MetEd, Penelec, West Penn (Allegheny), and PECO will see their generation rate caps expire at the end of 2010. Duquesne Light customers saw their generation rate caps expire at the end of 2004. As part of the investigation, the Commission also sought to assess various policies to mitigate the potential price increases. Following the submission of initial comments by interested parties, the Commission held an *en banc* hearing on June 22, 2006 to discuss the policy options proposed by the respondents, and asked for follow-up comments on a variety of issues.

The motivation of the Commission was concern over experiences with retail price increases in Pike County, Pennsylvania, as well as the Baltimore Gas & Electric territory in Maryland and the Delmarva Power Company territory in Delaware. In Pike County, retail rates increased by 85% following the termination of generation rate caps at the end of 2005. In the Delmarva Power Company service territory in Delaware, retail rates increased by 59% on May 1, 2006. In the Baltimore Gas & Electric Territory, the default supply auction yielded rate increases of 72% for default service. Aside from events in these three areas, the Commission expressed some concern that rate caps put in place just before an era of rapidly-rising and volatile fuel prices would inherently lead to price shock in Pennsylvania.

In its initial order,²⁹ the P.U.C. asked for comments on the following proposed strategies to mitigate the effects of electricity price increases:

- Educate consumers well in advance regarding the reasons for rate increases, and the workings of the wholesale electricity market in PJM;
- Encouraging conservation, through the use of market signals and the expansion of programs such as LIURP (Pennsylvania's low income usage reduction program);
- Encouraging demand response to reduce peak demand for electricity;
- Alternative strategies such as a phasing in higher prices over a few years instead of having one year of price shock;
- Re-evaluation of programs for low-income customers (the Pennsylvania competition act instructs load serving entities to provide universal service to low-income customers, and allows for recovery of the costs associated with these programs);
- Analysis of the link between wholesale and retail electricity markets.

In addition to the six items laid out by the whole Commission, Commissioner Bill Shane specifically asked respondents for comments on the following three issues:³⁰

- Long-term (multi-year) contracts for default suppliers;
- Potential benefits of relieving major transmission or other system constraints;
- Whether it is reasonable public policy to make default service so unattractive as to essentially force customers to shop for alternatives (this has become known as the "ugly POLR" issue).

Forty respondents filed comments. Not all respondents who filed initial comments filed reply comments (in response to issues raised at the *en banc* hearing). The distribution of respondents by industry sector is shown in figure 20. A detailed breakdown of the respondents is shown in table 6.

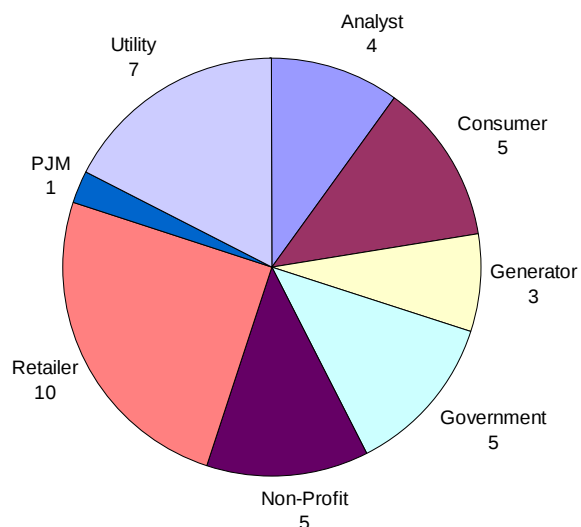


Figure 20. Distribution of Respondents and Reply Respondents to the Pennsylvania P.U.C. Investigation Order in Docket M-00061597.

Respondent Type	Number of Respondents	Respondents
Retailers	10	Constellation Energy, Customized Energy Services, Direct Energy, Dominion, Hess, National Energy Marketers Association, NRG, Reliant, Retail Electric Supply Association, Strategic Energy
Utilities	7	Duquesne Light, Energy Association of Pennsylvania, Met Ed, PECO, PPL, UGI, West Penn (Allegheny)
Consumers	5	AK Steel, Competitive Energy Markets Coalition, Industrial Energy Consumers of Pennsylvania, Pennsylvania Food Merchants Association U.S. Steel
Government Organizations	5	Allegheny Conference on Community Development, Dan Onorato, Pennsylvania Department of Environmental Protection; Office of Consumer Advocate; Office of Small Business Advocate
Non-Profit Groups	4	\$1 Energy Fund, Citizen Power, Penn Future, Small Business Development Council, Three Mile Island Alert
Analysts and Consultants	4	David Boonin, J3 Energy Group, Ken Davidson, Maureen Mulligan
Generators	3	Edison Electric Institute, Electric Power Generation Association, PV Now!
Regional Transmission Organizations	1	Pennsylvania-New Jersey-Maryland Interconnection (PJM)

Table 6. Respondents and Reply Respondents to the Pennsylvania P.U.C. Investigation Order in Docket M-00061597.

While some of the respondents (in particular, the larger retailers, utilities, and state-level governmental entities) submitted comments directly addressing the nine issues posed by the Commission, many others submitted very general comments describing their perceptions of the state of retail and wholesale electricity markets, deregulation in general, markets for natural gas, and power plant safety issues. Most respondents addressed more than one issue in their submitted comments. The policy suggestions offered to the commission were very diverse; the forty respondents to the Commission’s Investigative Order offered thirty-five distinct policy options. We divide the policy options into six broad classifications:

Market-Based Policies would seek to mitigate price increases through the further promotion of competition in regional spot electricity markets such as PJM;

Investment Policies that suggest building more generation or transmission can mitigate the effects of electricity price increases;

Regulatory Policies that seek to increase the role of the Commonwealth P.U.C. or other regulatory entity in determining retail prices;

Default Service Policies specific to the structure of default (or Provider of Last Resort) service utility tariffs;

Financial Policies aimed at adjustments to utility tax or debt structure, or other innovative financial arrangements aimed directly at mitigating the potential for higher electricity prices;

Other Policies that do not fit into any of the above categories.

A classification of the policy options offered to the Commission is given in table 7. There is some variation among respondents within individual policy suggestions described here. For instance, many respondents support a market-based POLR rate structure. However, some respondents interpret “market-based” to mean that the rates should be based on hourly market prices, while others suggest that longer-term contracts should be allowed, but the price should be determined by the market and not by individual bilateral negotiations or a regulated contract rate. As another example, some proponents of tax reform would like to see taxes lowered to encourage investment in new infrastructure or to increase the competitiveness of Pennsylvania, while other proponents of tax reform would like to see taxes increased to direct more resources to local governments.

Policy Classification	Policy Suggestions
Market	Encouraging competitive wholesale markets Real-time or time-of-use pricing Removal of wholesale price caps
Investment	Encourage RTO transmission planning Build more generation Invest in alternative energy sources Produce more natural gas
Regulatory	Demand-side management and other utility conservation programs Reconsider market-based pricing

	Restore cost-based utility regulation Establish a State public power authority Reverse utility generation divestiture Increase regulatory certainty Extend price caps Performance-based rate regulation Reduce the burden of environmental laws Mitigate market power more forcefully in wholesale markets
Default Service	Market-based default service Long-term default service contracts Uniform default service tariffs for all utilities in Pennsylvania Auctions for default service Staggered utility procurement of generation to serve default load (similar to the New Jersey model) Require diversity of supply for default service
Financial	Phase-in of rate increases Tax reform Eliminate cross-subsidies Establish a statewide volatility prevention fund Allow for individual energy savings accounts Asset-based financing for long-term contracts
Other	Educate consumers Form a working group to study the potential for large price increases and to evaluate potential mitigation policies

Table 7. Classification of specific policy suggestions offered under the Pennsylvania P.U.C. Investigation Order in Docket M-00061597.

The next several figures show the distribution of particular policy suggestions by industry segment. The figures, with the exception of figure 21, do not include specific data for PJM or for the Generators group. PJM submitted comments on its market performance, market design, and proposed market redesign. It did not directly address any of the questions raised by the Commission. Two of the three respondents in the Generator group also did not directly address the Commission's questions. The Edison Electric Institute (EEI) submitted a set of slides showing how utility cost drivers have increased. This information is useful in and of itself, but did not address the specific concerns or questions raised by the Commission. PV Now! is a special interest group for solar energy; their comments were aimed at the impact of the Commission's proposals on the solar power industry and not on consumers. The Electric Power Generation Association made the most concerted attempt to address the questions raised by the Commission. In their comments, they supported the loosening of environmental regulations and market-based POLR rates. They also mentioned fuel prices as a major factor in higher electricity prices, as well as costs associated with Pennsylvania's Alternative Energy Portfolio Standard.

For each policy suggestion, the histogram shows the number of respondents supporting that suggestion. Since an individual respondent could suggest or support multiple policy options, the total number of policy suggestions greatly exceeds the total number of respondents. Overall, programs to educate consumers and utility conservation programs were suggested the most often, followed by market-oriented responses such as encouraging competition at the wholesale and retail level, and some kind of real time or time-of-use pricing for all customers.

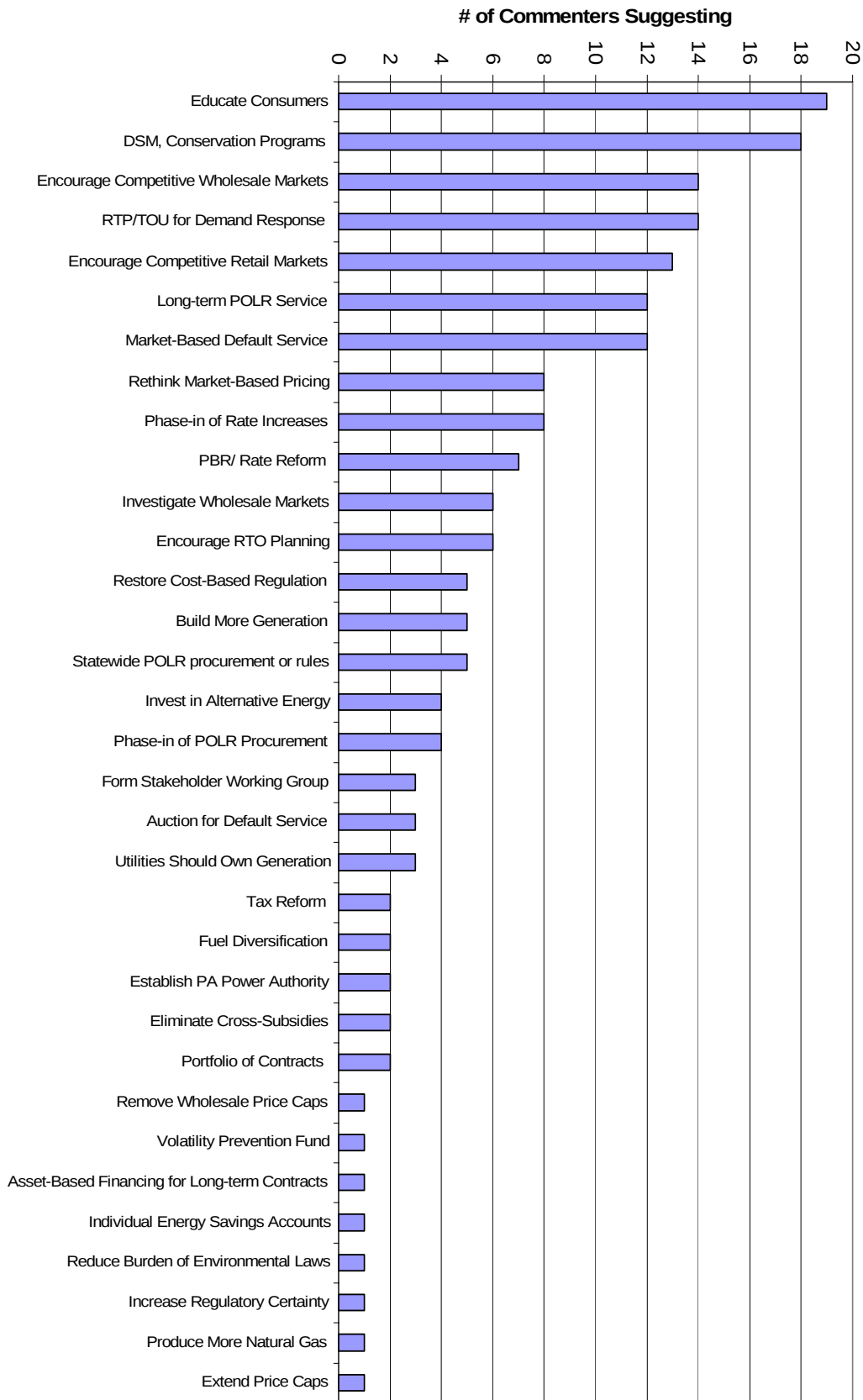


Figure 21. Histogram of policy responses; all respondents (including PJM and the generator industry group).



Figure 22. Histogram of policy responses by the retailer industry group.

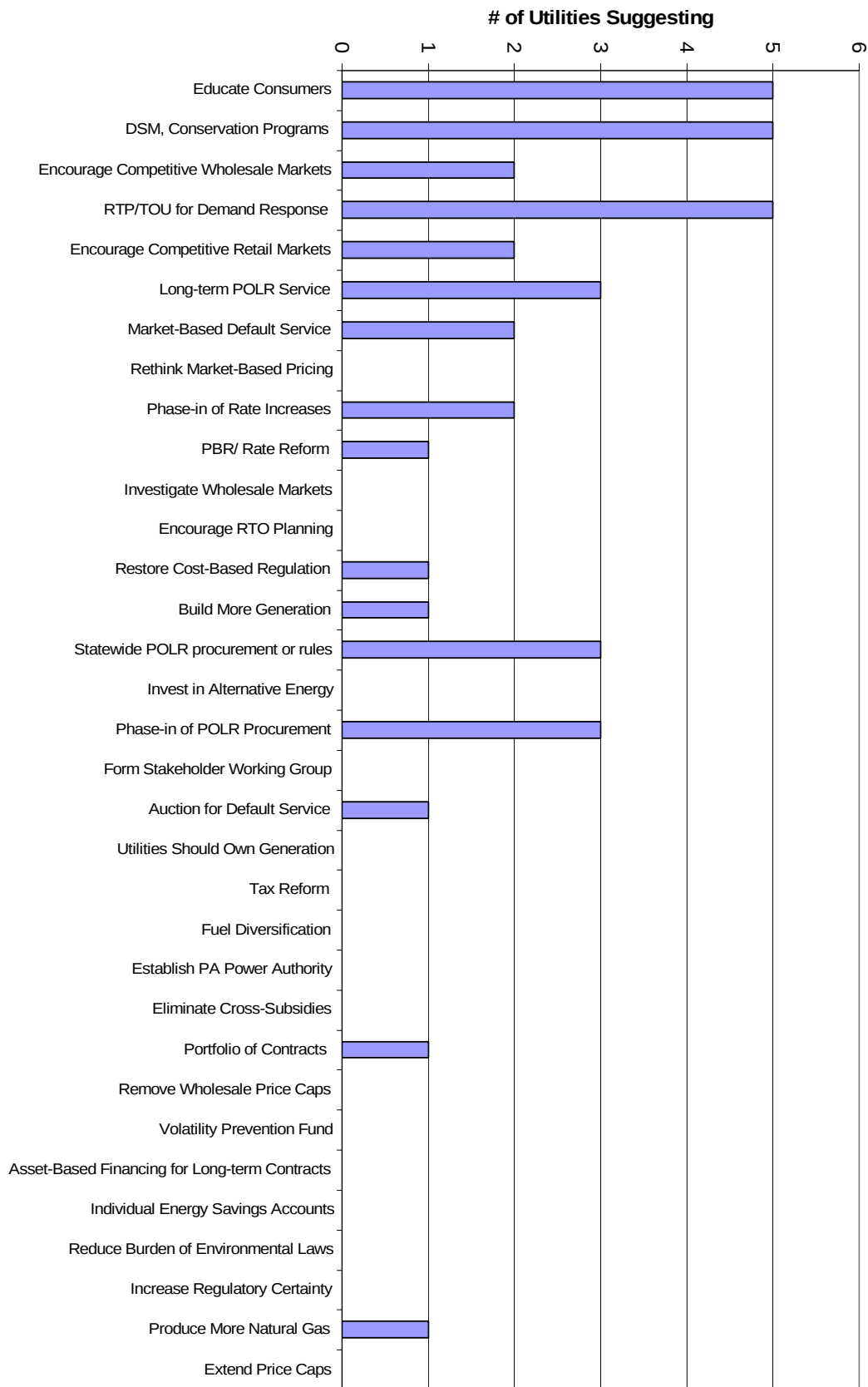


Figure 23. Histogram of policy responses by the utility industry group.

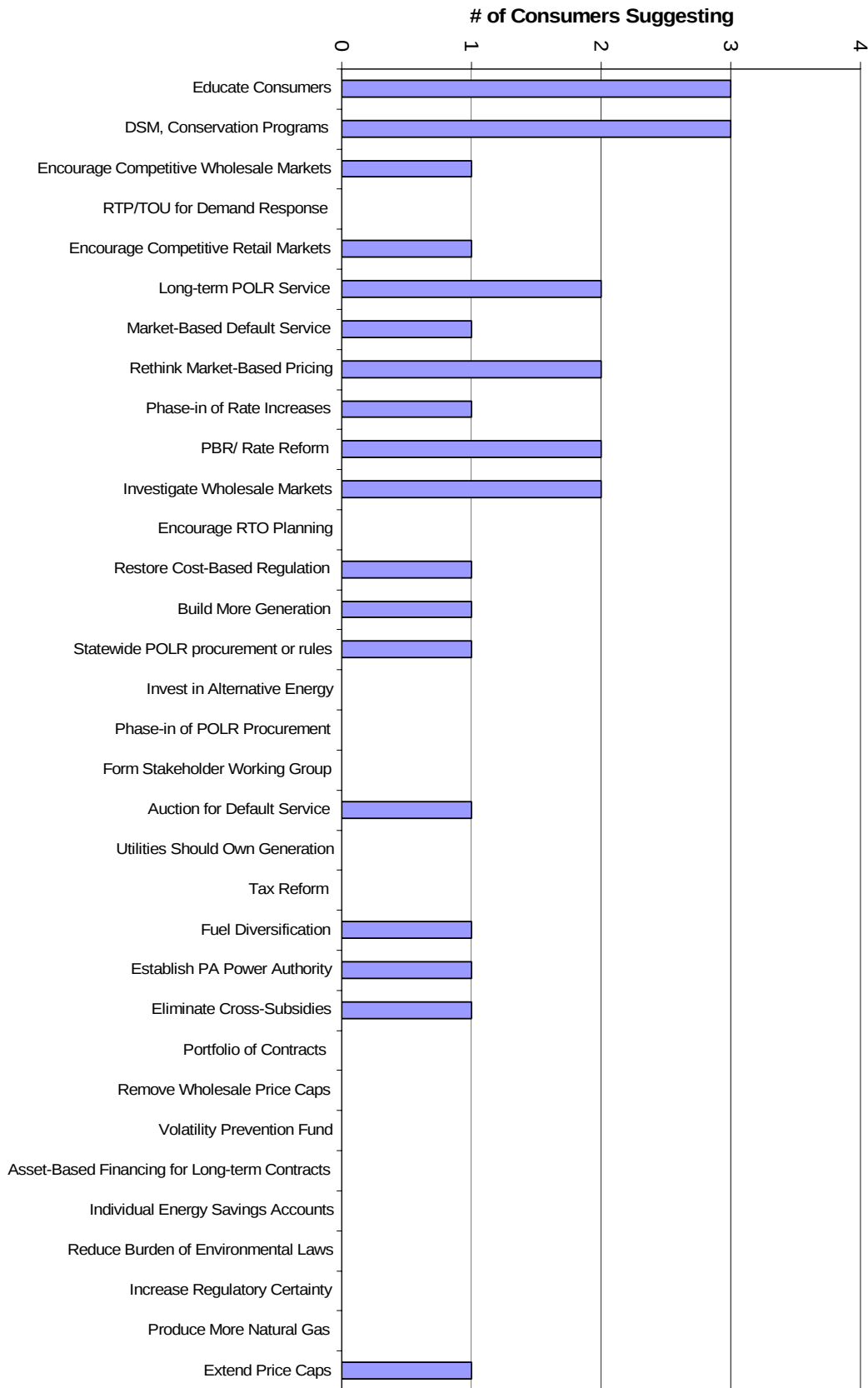


Figure 24. Histogram of policy responses by the consumer industry group.

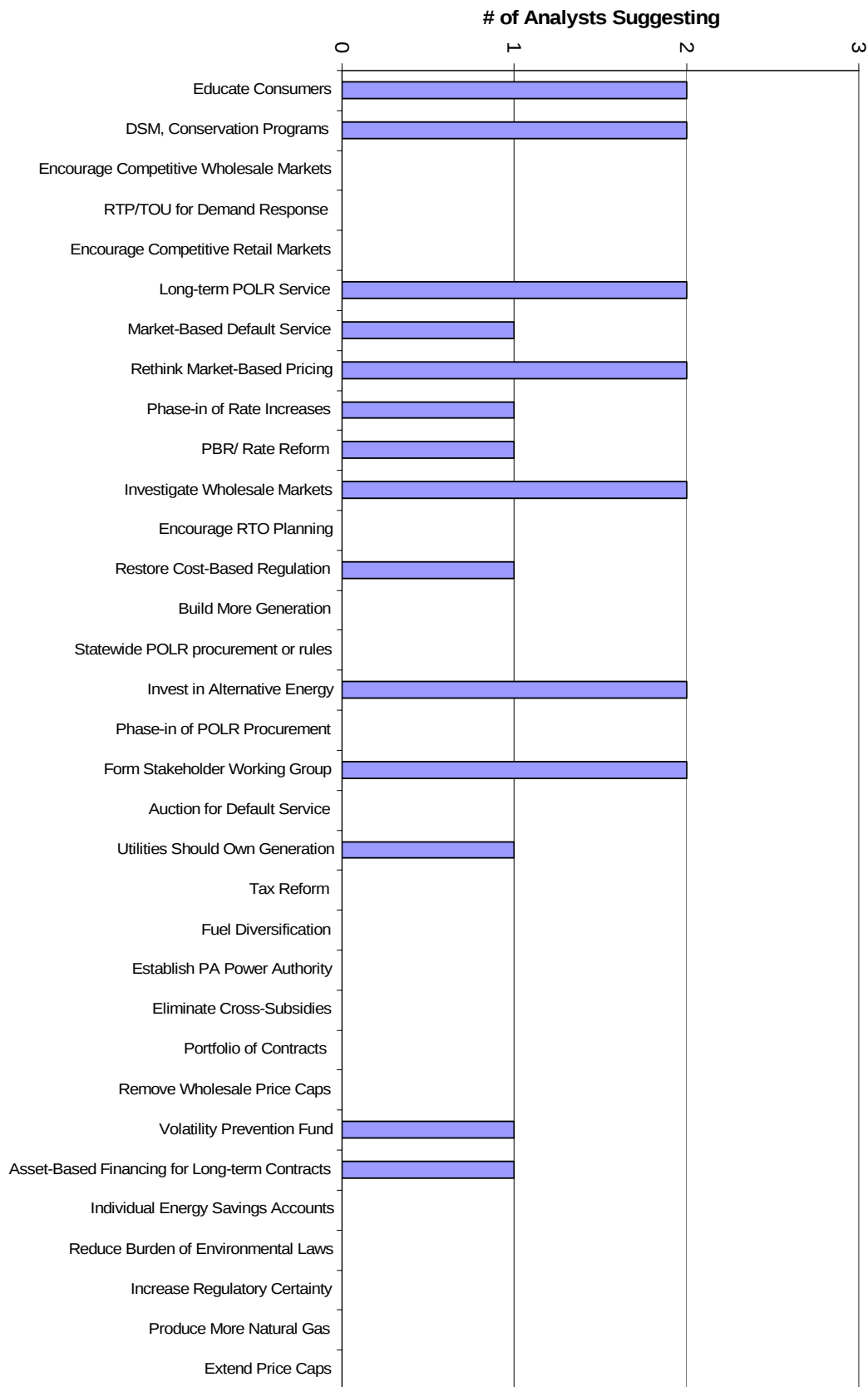


Figure 25. Histogram of policy responses by the analyst and consultant industry group.

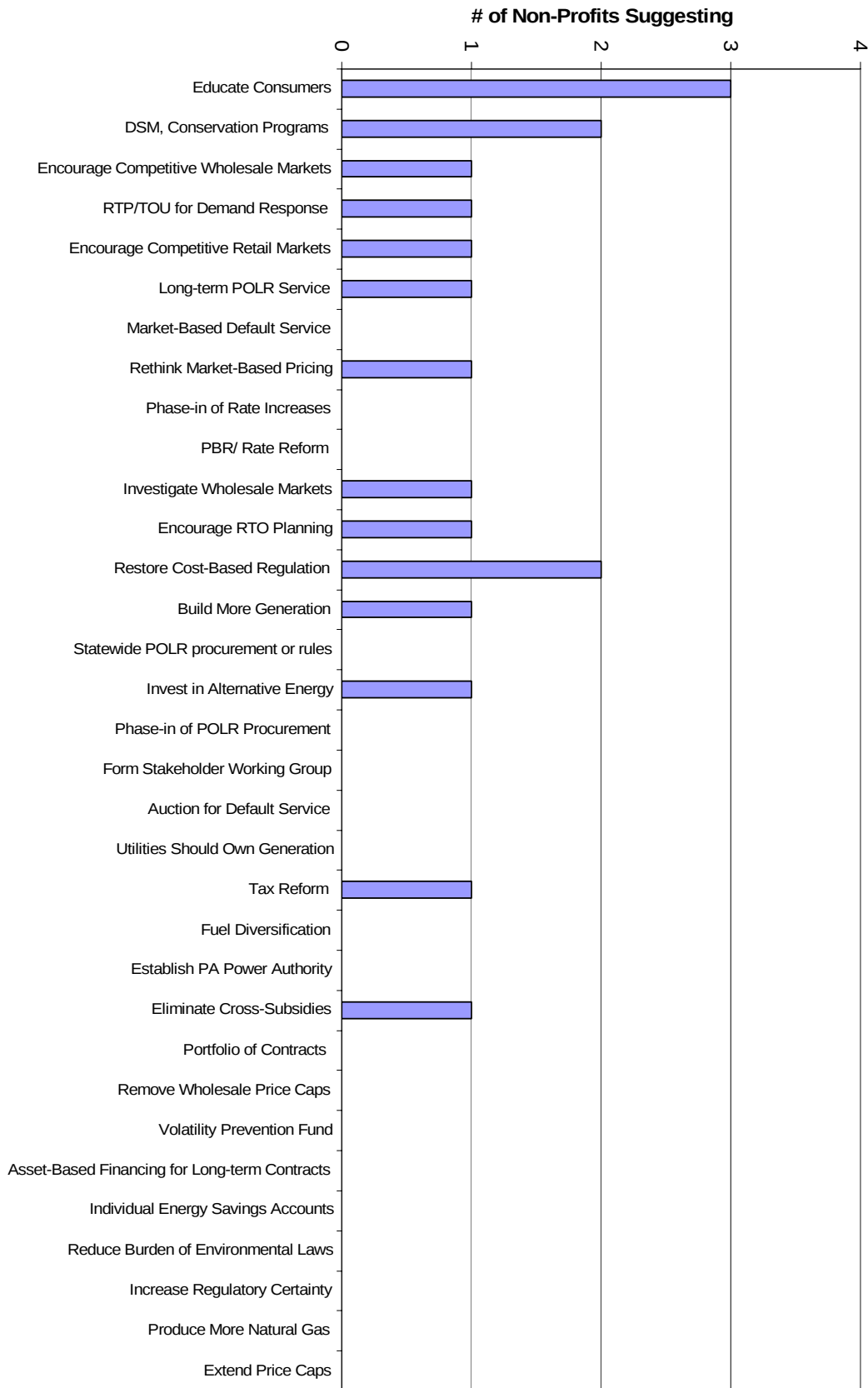


Figure 26. Histogram of policy responses by the non-profit industry group.

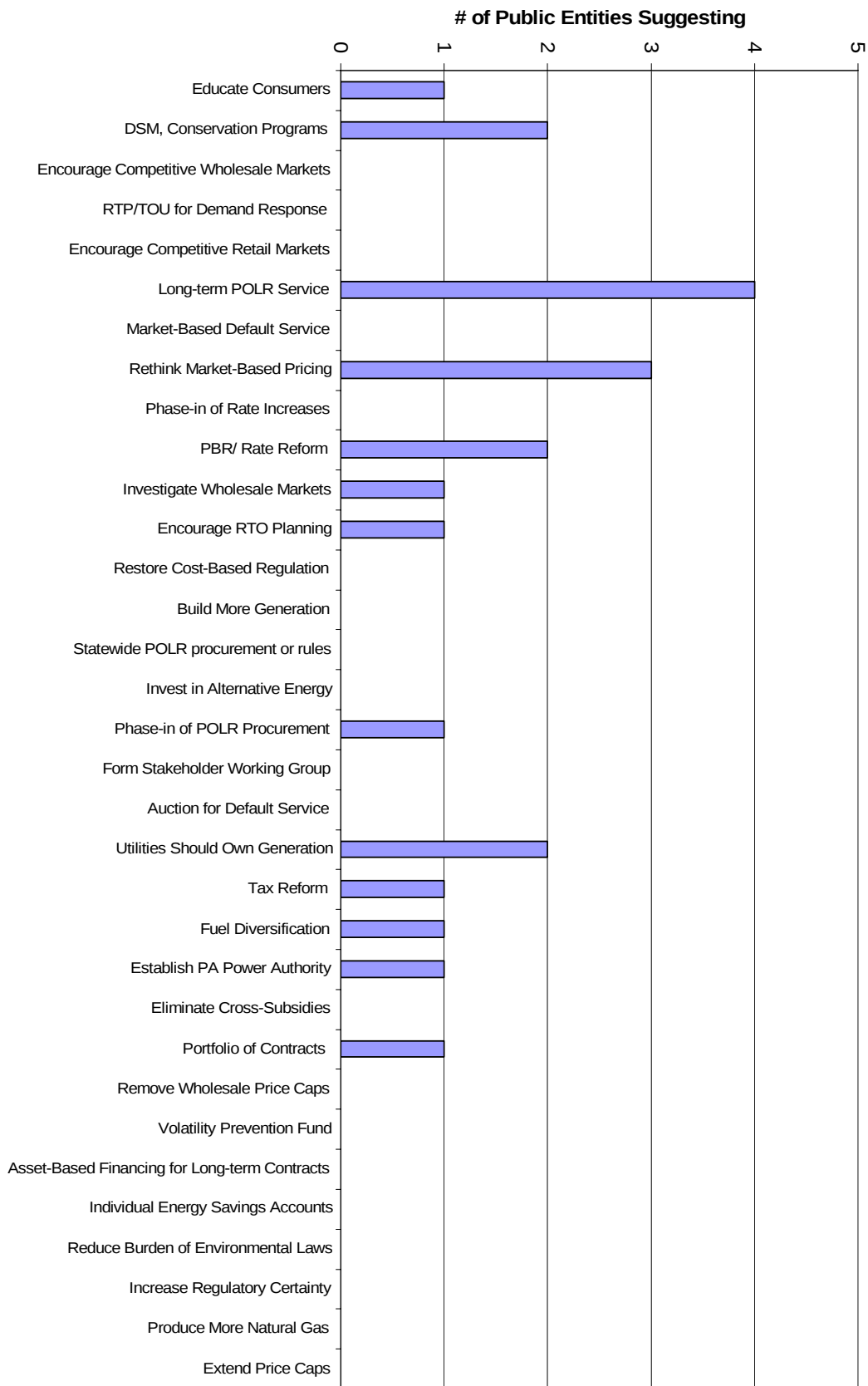


Figure 27. Histogram of policy responses by the government industry group.

The comments reveal deep disagreements over what policies (if any) the Commonwealth should pursue to mitigate the effects of electricity price increases. Some respondents, such as PECO, suggested that prices will not actually rise very much at all.³¹ Retailers and generators generally favor market-oriented policies and market-based default service pricing, while large industrial customers and utilities generally favor regulation-oriented policies and allowing long-term default service contracts. Five out of ten utilities favored allowing customers to be on real time or time-of-use pricing, but generally not as a default service option. Non-profit groups also tended to favor regulatory solutions, although a few suggestions were made in favor of competition at both the retail and wholesale level. Respondents in the governmental industry group (which is made up primarily of development authorities and advocates for smaller electricity consumers) overwhelmingly support regulation-oriented solutions. In particular, this sector appears more critical of the institutions and markets created through restructuring than any other group of respondents. The governmental industry group was the only one in which no respondent advocated a market-oriented policy response to mitigate the potential effects of higher electricity prices.

The comments also suggest a number of different interpretations of the Pennsylvania Electric Competition Act.³² Differences in opinion are especially contentious surrounding what the Competition Act has to say regarding permissible default service pricing. The exact language of the Act is:

§ 2807 (e)(3) if a customer contracts for electric energy and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or commission-approved alternative supplier shall acquire electric energy at *prevailing market prices* to serve that customer and shall recover fully all reasonable costs. [emphasis added]

The controversy surrounds the phrase “prevailing market prices.” Some respondents suggested that the Act should be interpreted as the Commonwealth endorsing only hourly market pricing for all default customers. Others argued that the intention of the Act would be satisfied if default service is procured through a competitive auction or bidding process for long-term contracts (which should have at least some relationship to market prices). Differences of opinion tend to fall across industry-group lines. All but two retailers suggested that at least all large customers should have mandatory hourly pricing as the default service. Many retailers qualified this by adding that, at least until technology develops and the ability of consumers to respond to changes is determined, residential consumers should be allowed to have a fixed monthly default rate. On the utility side, there was some enthusiasm for using real time pricing to encourage reductions in peak demand, but only two utilities (Med Ed/Penelec, owned by FirstEnergy; and West Penn/Allegheny) supported market-based default service. Both Allegheny and FirstEnergy have historically been low-cost generators. Allegheny’s industrial rates, for example, have generally been below LMPs in the West Penn zone.

Other respondents suggested that Pennsylvania might be constrained in its policy decisions by the Energy Policy Act of 2005. National Energy Marketers, for example, suggested that the Energy Policy Act requires vertically-integrated or distribution utilities to offer real time or time-of-use pricing (along with installing meters to support the service) for conservation purposes. The relevant sections of the Energy Policy Act of 2005 are:

§ 1252(a) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility’s costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

§ 1252(f) It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity, and ancillary services markets shall be eliminated.

There does not appear to be any language in the Energy Policy Act which suggests that Pennsylvania is obligated to establish a market-based default service rate, or that Pennsylvania would not have sufficient latitude in designing its own default service tariffs.

Some of the respondents suggested policies involving tax and financing reforms, particularly to provide incentives for the construction of new generation. One such policy has been referred to as “asset-backed financing.”³³ Under such a policy, investors could obtain lower costs of capital by using the physical asset as collateral (similar to a mortgage on a home). For such a policy to work, the asset would need to have a certain stream of future revenues, such as a long-term purchase contract. Thus, the Commonwealth would need to allow load serving utilities to offer long-term contracts to its default customers, and would in effect re-integrate those load serving entities that divested their generation following the passage of the Competition Act. Thus, it would be tantamount to re-regulation of new plants, since the Public Utility Commission would need to establish performance standards and undertake prudence reviews.

In summary, most of the respondents did address at least some of the issues raised by the Commission. Nearly all of the respondents identified and supported policy options that would benefit them the most, rather than those that might help the most customers or would most help the Commonwealth as a whole. Competitive suppliers and generators tended to favor market-based solutions as a way to promote economic efficiency and eliminate subsidies. Large consumers tend to favor regulatory solutions as a way to ensure a competitive business climate, believing that they had enjoyed favorable rates under regulation. Thus, the distribution of responses to the Commission should be taken as indicative of the numbers and industry segments of the respondents. Particular policy alternatives supported by a large number of respondents should not necessarily be those that the Commonwealth ought to pursue most vigorously.

2.3 Insights from other restructured markets

While there have been differences in the details, the basic restructuring and retail competition models followed by those states that have chosen a path of restructuring has been reasonably homogenous.

In the majority of states that enacted restructuring, a political bargain was struck that offered consumers a rate freeze (in some states only for residential customers) while utilities recovered their stranded costs. No states increased rates and then froze them. Rather, each state either lowered rates and froze them or froze existing rates. In either case, the states and utilities assumed that the cushion between falling costs and the frozen rates would allow the utilities to pay off stranded costs (known as “competitive transition charges” in Pennsylvania). During the transition period, utility customers have generally been free to stay with the distribution utility or to purchase generation service from a competitive third-party supplier.³⁴

Those who do not choose a competitive supplier or those who otherwise must leave their competitive supplier fall back on the default service provider (most often the incumbent distribution utility). There has been some variation among states in determining the price and other service terms for

this default service, as well as contracting for the energy required to serve default customers (particularly when the distribution utility has divested itself of generation assets).³⁵ New Jersey, Maryland, and Illinois recently conducted auctions to determine the default supply price. Particularly given the experience of Pike County in conducting its own auction for default service, a short review of the auction structure and results can be helpful in determining how the Commonwealth handles default service provision in the post-rate-cap period. This section will also provide a short discussion of the Connecticut request for proposal (RFP) for peaking generation (even though the results will not be publicly available by the time this study is complete) since it represents a significant departure from the resource adequacy policies pursued in the eastern RTOs.

While most states did not follow the lead of California and explicitly require utilities to divest generation and vertically dis-integrate, physical or virtual divestiture (in the form of a “Chinese Wall” limiting contact between the generation and distribution utility businesses) has been commonplace. The decision of whether to surrender control of the transmission network and join an RTO such as PJM has been left to individual utilities.

Table 8 summarizes the retail price changes following the expiration of price caps in seven states for which data are available.

State	End of Price Caps	Percent Change Following End of Price Caps
Delaware ^a	May 2006	47% - 118%
Illinois ^a	January 2007	16% - 130%
Massachusetts ^b	March 2005	0%
Maryland: PEPSCO/DPL ^a	July 2004	13% - 57%
Maryland: BG&E ^a	July 2006	14% - 72%
Maine ^b	May 2000	0%
New Jersey ^b	August 2003	20%
Texas ^c	January 2002	30%

Table 8. Retail price changes following expiration of price caps.

a: Based on data from the respective State PUC comparing rates immediately before the termination of rate caps with the results of the default supply auction.

b: Based on comparison of EIA Form 826 data for the month preceding the termination of rate caps, and the month that rate caps were terminated.

c. Based on comparison of EIA Form 826 data for the month preceding the termination of rate caps, and data on the “price to beat” from the Texas PUC.

Notes to table 8:

1. “End of Price Caps” signifies the date (the first of the respective month) when rate caps were removed, and replaced with each state’s respective POLR rate.
2. Until 2005, Massachusetts had complex rules placing certain customers on fixed rates and others on a market-based default rate. In 2005, Massachusetts completed the transition to all customers facing a market-based default rate.
3. This table reflects all rate classes, since data are not always available for each rate class separately.
4. Maryland ended its rate caps on different dates for different utilities. Allegheny Energy’s rate caps do not expire until 2008. Allegheny Energy has announced that their Maryland customers will have a 75% rate increase at that time.
5. The figure for Massachusetts represents a very small increase (approximately 0.2%), while the figure for Maine represents a very small decrease (approximately -0.4%).
6. BG&E’s rate increase of 72% will be phased in over a number of years.

2.3.1 New Jersey auction

The generation component of the price (and supplier) for customers in New Jersey that have not selected a supplier is determined by a multi-round simultaneous auction. The results of the auctions for 2002 through 2006 for commercial and small industrial customers are reproduced from Rose and Meeusen³⁶ below.

	2002 Auction	2003 Auction		2004 Auction	2005 Auction		Percent Increase - 04 to 05	2006 Auction	Percent Increase - 05 to 06
	12 month	10 month	34 month	12 month	36 month	36 month		36 month	
Conectiv/ ACE	5.12	5.260	5.529	5.473	5.513	6.648	20.6%	10.399	56.4%
JCP&L	4.87	5.042	5.587	5.325	5.478	6.570	19.9%	10.044	52.9%
PSE&G	5.11	5.386	5.560	5.479	5.515	6.541	18.6%	10.251	56.7%
Rockland	5.82	5.557	5.601	5.566	5.597	7.179	28.3%	11.114	54.8%

Table 9. Results of the New Jersey auctions (cents per kWh) reported by Rose and Meeusen.

The auction is for the generation component only, and retail prices include other charges, so the final customer charge is less than the percentage increases in generation price.

2.3.2 Maryland auction

Following the expiration of rate caps for each of the state's distribution utilities, Maryland conducted a single auction to determine default service prices over a three-year period. The auctions were staggered in the sense that the length of the service contract awarded ranged from 11 to 35 months (24 months for non-residential service), but the bidding for all of these contracts took place at once. Half the contracts were for 11 months, one quarter for 23 months and one quarter for 35 months. The results of the 2006 default supply auction have been widely publicized. The increases for the generation component of the bill were between 52 and 132 percent, depending on the utility. These generation costs were passed along to the customers along with charges such as transmission and distribution that did not change. Thus, the final customer bill increased less than the generation component. Residential customers of Baltimore Gas & Electric saw a 72% retail price increase (although this price increase will, by legislative decree, be phased in over a number of years, with annual increases limited to 15% or less).³⁷ PEPCO and DPL residential customers saw rate increases of 39% and 35%.

Maryland provides an interesting contrast to Illinois (discussed below) in that the residential default price increases appear to be larger than the price increases for commercial customers. A comparison of the residential and commercial total bill increases for default service is in table 10.³⁸

	Residential	Small Commercial	Medium Commercial
PEPCO	39%	52%	53%
DPL	35%	40%	14%
BG&E	72%	39%	27%

Table 10. Total bill increases from the 2006 Maryland default service auction.

Source: Maryland Public Service Commission.

2.3.3 Illinois auction

Like the Maryland auction, the Illinois auction for default service sought to procure generation for multiple contract lengths: 17, 29, and 41 months for smaller customers (residential and small commercial), and only 17 months for larger commercial and industrial customers. Like New Jersey, the Illinois auction used a descending-clock format, in which the auction is run continuously with the participants offering various quantities of supply. The auction price is determined by the auctioneer, and is systematically lowered as the auction proceeds. The final price is determined by the point at which the total quantity offered in the auction equals the desired default service supply.³⁹

Illinois ran two auctions in parallel. The first was for a fixed-price default service and the second was for an hourly-price default service for large commercial and industrial customers. The results of the fixed-price auction for small and medium residential and commercial customers yielded prices between 6.3 and 6.6 cents per kWh. In the fixed-price auction, there was no consistent risk premium placed on longer-term contracts for small and medium customers (the lowest-priced product in the auction was a 41-month contract in the ComEd service territory, and the highest-priced product was a 41-month contract in the Ameren service territory).

The auction results for large customers were quite different; 9.012 cents per kWh for a 17-month contract in the ComEd territory and 8.495 cents per kWh for the same contract in the Ameren territory. The hourly service auction for large customers yielded prices of 17.535 cents per kW-day in ComEd and 27.619 cents per kW-day in Ameren. Because of the high prices, the Illinois Commerce Commission (ICC) rejected the results of the hourly default service auction. The ICC did accept the results of the fixed price service auction, but noted that the prices for large customers were much higher than expected, and reflected a risk premium as high as 68% for a 17-month contract with a large customer.⁴⁰ The ICC attributed much of this to quantity risk – the risk that large customers would either switch frequently between competitive suppliers and the default supplier, or that large customers would be more susceptible to swings in the economic business cycle and could start up or shut down unexpectedly.

2.3.4 Auction prices and wholesale prices

Rose and Meeusen analyzed⁴¹ the differential between mid-Atlantic state auctions and PJM real time locational marginal prices in 2004 and 2005. The markup from the wholesale to the auction price in 2004 ranged from 21 to 48 percent. In 2005 the markup ranged from 55 to 74 percent. Rose and Meeusen conjecture that the increase in markup between 2003 and 2005 is due to increased LMP variability. An alternative explanation is that the locational price differences across PJM have grown over time. Figures 8, 18 and 19 show that transmission congestion can cause significant price differences between eastern and western PJM. The retail prices in the Rose and Meeusen analysis represent some of the most highly-congested areas in PJM. Thus, a better comparison is between these retail prices and their associated LMPs (not an average LMP encompassing all of PJM).

Whether the increase in the markup is due to increased LMP variability in 2005 (as conjectured by Rose and Meeusen) or to another factor, it is clear that auctions have led to prices for default supply that are considerably above the spot market average prices.

2.3.5 The Connecticut generation request for proposals

Generation investment in the U.S. has fallen dramatically from the late 1990s when non-utility gas-fired plant construction was at its peak. Paul Joskow reports that planned capacity additions have fallen by a factor of twenty since 2000.⁴² Resource adequacy during peak demand periods has been a concern among all of the RTOs, particularly in the Northeast, which is generally not blessed with inexpensive native generation sources such as coal. Meanwhile, as peak demands have increased, the congestion charges seen in LMP markets have also increased, both in total and on average. However, the high congestion charges have not been sufficient to encourage investment, particularly in peaking generation.

In June 2005, Connecticut passed Public Act 05-01 (known as the Energy Independence Act), that represents an attempt to circumvent the RTO generation planning process for peaking generation, demand response resources, distributed generation, and long-term capacity contracts. The Act directs the Connecticut Department of Public Utility Control (DPUC) to issue a request for proposals (RFP) and conduct a competitive bidding process for these four resources. The Connecticut RFP specifies a long-term (up to 15 years) contract for capacity at a fixed price, though in practice this would be settled against the capacity market in ISO New England.⁴³ The contracts may also include a call option provision, under which the bidder would get a supplemental capacity payment whenever the LMP exceeds the strike price specified in the call option. Thus, the effect of the Connecticut RFP is not necessarily to lower prices, but rather to provide Connecticut customers with a physical hedge against volatile congestion charges in the ISO New England spot market. Since the bids have not been made public at the time of this report, it is difficult to ascertain the exact price effects that the RFP will have. If the Connecticut RFP is successful at lowering price or reducing volatility (both of which are important to commercial and industrial customers in Pennsylvania), it could provide a model for the Commonwealth to engage in its own procurement process for new generation resources located in currently-constrained areas.⁴⁴

3. FACTORS INFLUENCING PENNSYLVANIA PRICES

3.1 Market effects

Electricity consumers in Pennsylvania are served by three distinct RTOs. The majority of the state is within the PJM footprint, but West Penn consumers are served through the Midwest ISO (MISO) and Pike County is part of the New York ISO. All three of these RTOs use similar models for conducting their day-ahead and real time electric energy auctions. Generators submit supply bids (prices and quantities), and the aggregate supply curve constructed by the RTO determines which generators get dispatched and the market-clearing price. This auction structure is known as the uniform-price auction because, in the absence of transmission congestion, every generator whose bid is accepted would earn the market-clearing price. In other work,⁴⁵ and in Section 1.2, we have discussed ways in which this auction structure may act to increase costs by paying all generators based on the bid of the marginal unit rather than average cost, as occurred under regulation.

Since transmission congestion is endemic to the PJM market, particularly between Western PJM and Eastern PJM, LMPs vary widely from location to location. Figures 28 through 31 show monthly 24-hour average LMPs in the Duquesne, West Penn (Allegheny), PPL, and PECO territories, along with average industrial retail rates.

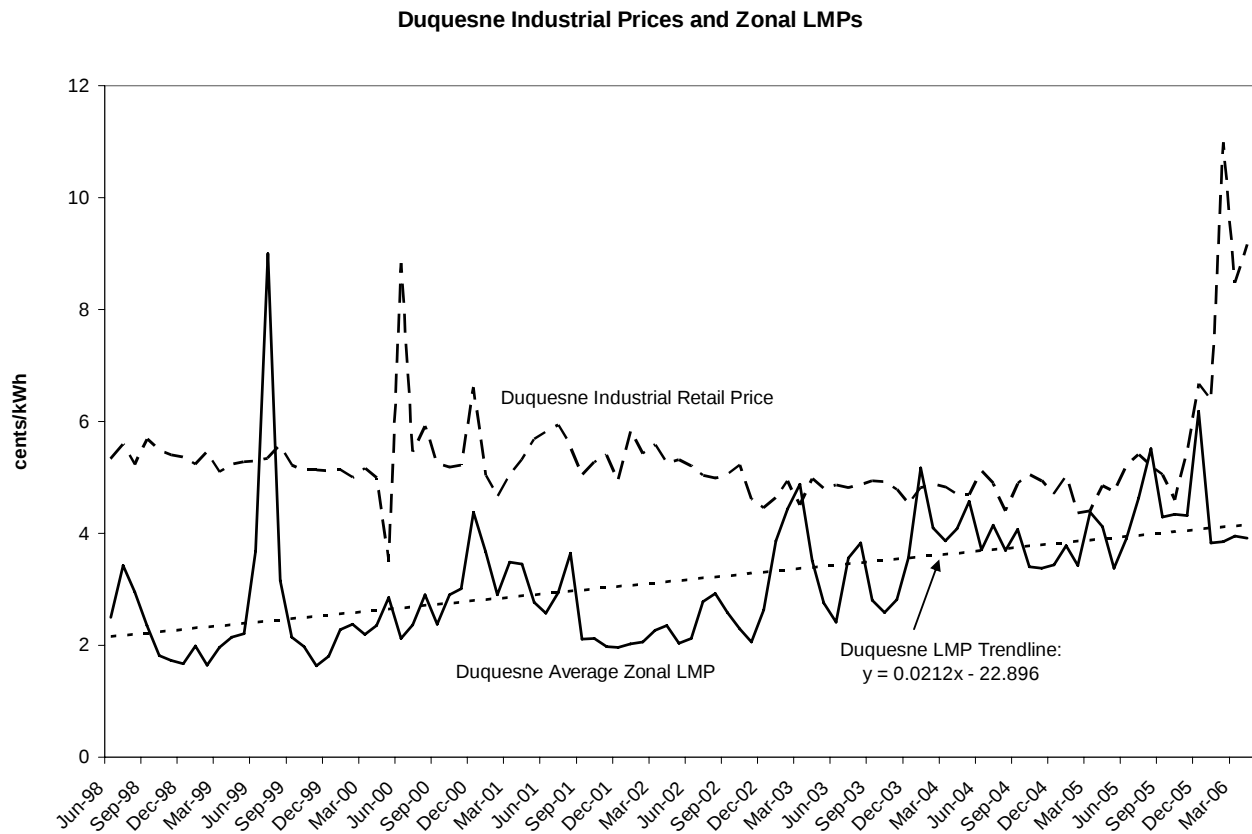


Figure 28. Average industrial retail prices and LMPs in the Duquesne territory.
Data source for figures 28-31: EIA form 826 and PJM.

West Penn (Allegheny) Industrial Prices and Zonal LMPs

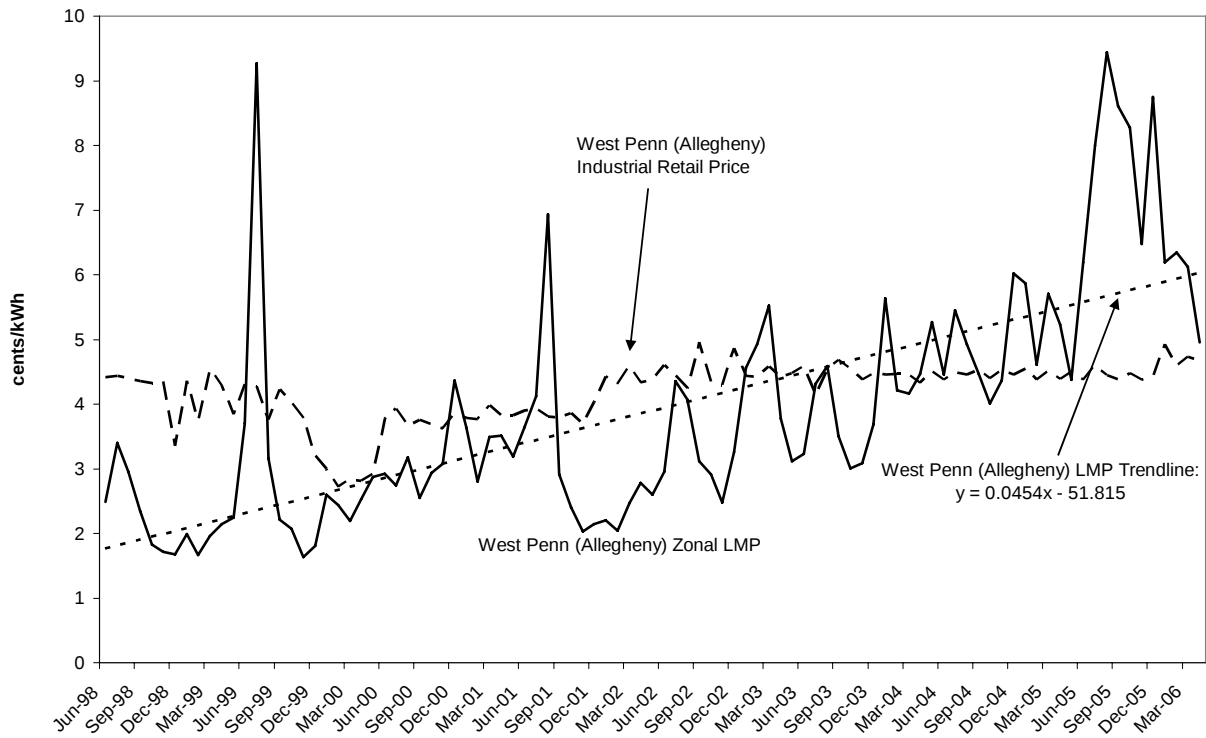


Figure 29. Average industrial retail prices and LMPs in the Allegheny territory.

PPL Industrial Prices and Zonal LMPs

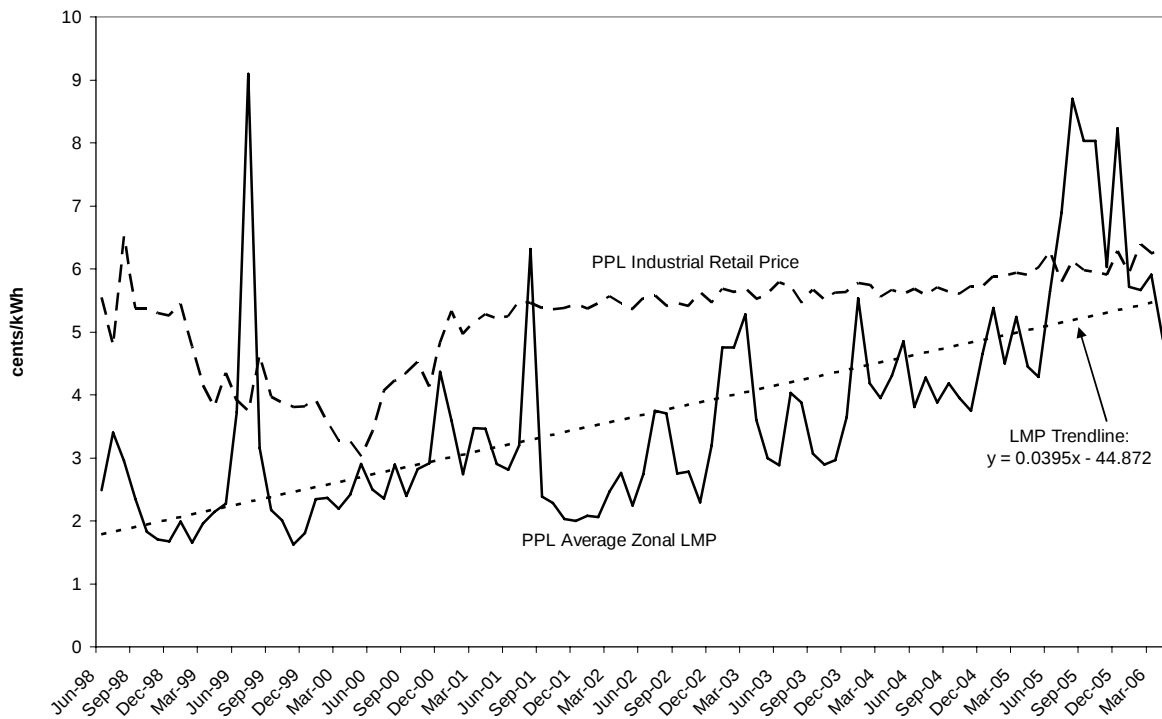


Figure 30. Average industrial retail prices and LMPs in the PPL territory.

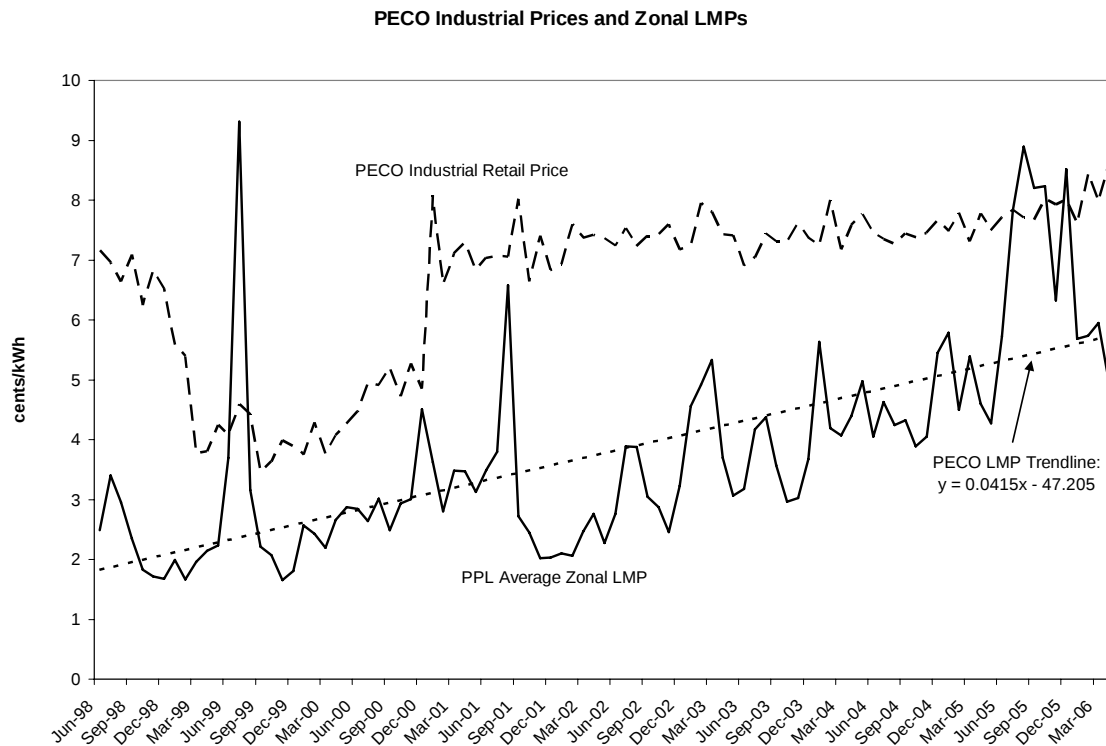


Figure 31. Average industrial retail prices and LMPs in the PECO territory.

An examination of figures 28 through 31 reveals the following:

Systematic differences in LMPs in different parts of Pennsylvania have grown over time. Prior to the completion of PJM's expansion in 2005, prices in the PECO service territory were, on average, 0.33 cents per kWh higher than prices in the Western PJM Hub. Since 2005, this average price difference has grown to 2.05 cents per kWh.

Market prices in Eastern Pennsylvania have risen much faster than market prices in Western Pennsylvania. The trendline in figure 28 shows that LMPs in Western PJM and the Duquesne zone have increased at an annual average of 0.02 cents per kWh since 1998. LMPs in the PECO, PPL, and Allegheny zones (shown in figures 29 through 31) have increased at roughly twice that rate.

Utilities in Pennsylvania have very different cost structures. Duquesne and PPL have been able to offer industrial service for an average of 5.3 cents and 5.2 cents per kWh since 1998. Due in part to its coal generation holdings, industrial rates for Allegheny have been, on average, one cent per kWh less expensive than Duquesne or PPL. PECO has the highest industrial rates, which have averaged 6.6 cents per kWh.

Some utilities, particularly PECO and PPL, appear to have offered their industrial customers quite favorable long-term contracts between late 1999 and early 2001.

Industrial customers appear to have had varying exposure to market prices. PPL and Allegheny's average retail industrial prices do not vary with the LMP as much as average industrial prices in Duquesne and PECO.

3.1.1 Fuel prices

The majority of Pennsylvania's capacity (roughly 60%) is in coal and nuclear generation. Approximately 15% of the generation capacity in Pennsylvania is natural gas, and another 5% is listed as oil-fired.⁴⁶ Pennsylvania's mix of major generation sources (60% coal and nuclear, and 20% natural gas and oil) is approximately representative of PJM as a whole. However, there are large differences in capacity and generation in PJM, as shown in table 11 (and figure 13 earlier in this report). While coal and nuclear make up 60% of PJM's installed capacity base, these generation sources together generate 90% of the electricity consumed in PJM. Natural gas and oil combined generate less than 7%.

	Installed Capacity (%)	Generation (%)
Coal	41.5	66.6
Nuclear	19.1	25.2
Natural Gas	27.5	5.6
Oil	7.2	0.9
Hydro	4.3	1.3
Wind	<0.01	0.1
Waste	0.3	0.4

Table 11. Generating capacity and output for PJM, 2005 (all figures in percentages).
Source: PJM 2005 State of the Market Report.

PJM generated only 5.6% of its electricity with natural gas in 2005. According to PJM's State of the Market Report, natural gas units set the market price for 26% of the kilowatt-hours consumed in 2005. However, this percentage considers only the hours in which natural gas set the price throughout the large PJM territory. Transmission constraints often mean that an area cannot be served by an inexpensive coal generator, but rather must be supplied by a natural gas generator. For example, the last kilowatt of demand in Pittsburgh might be served by coal while at the same time the last kilowatt of demand in Philadelphia would have to be served by natural gas. Our calculations based on PJM data show that natural gas set the market price in at least some areas of PJM during 75% of the hours in 2005.⁴⁷ The distribution of the weight given to natural gas in calculating the hourly LMP is shown in Figure 32.

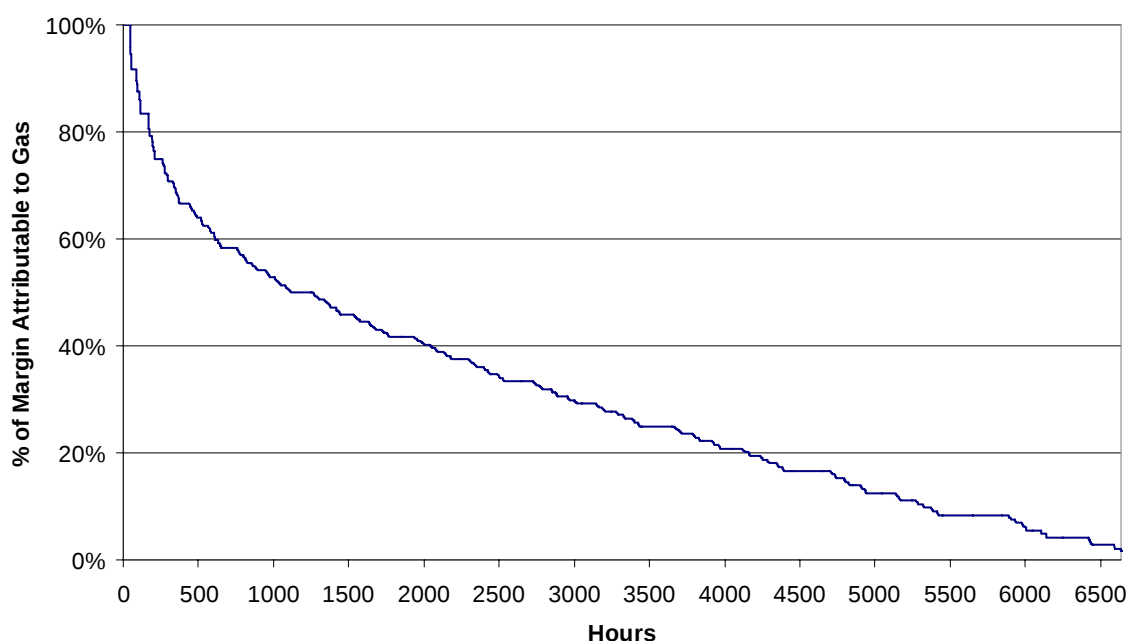


Figure 32. Distribution of the percentage contribution of natural gas to the hourly LMP in PJM for 2005. Data source: PJM. As an example of how to use this figure, at the 1000-hour per year point, the LMP is set by a weighted average price of half natural gas and half other fuels.

Figure 32 shows that there are very few hours in PJM where the market price is set completely by natural gas, although gas is still an important factor in determining the market-clearing price and the LMPs in PJM. Figure 33 shows an estimate of the short-run PJM marginal cost curve. We assume fuel prices of \$7/ MMBTU for natural gas, \$11.20/ MMBTU for oil, and \$2.20/ MMBTU for coal. Marginal costs for nuclear and hydro are assumed to be \$10/MWh, while the marginal costs of wind and biomass are assumed to be \$40/MWh and \$50/MWh, though these two sources do not figure heavily in PJM's generation mix. Fuel prices are converted to electric energy prices using plant-level average heat rate data from the U.S. Environmental Protection Agency's Emissions & Generation Resource Integrated Database⁴⁸ (eGrid). Figure 33 shows that given sufficient transmission, roughly the first 70% of PJM's load could be covered by low-cost coal, nuclear, and hydro generation. The shoulder units (where the marginal cost curve starts its steep upturn) are generally natural gas, while the peaking generators are primarily oil-fired.

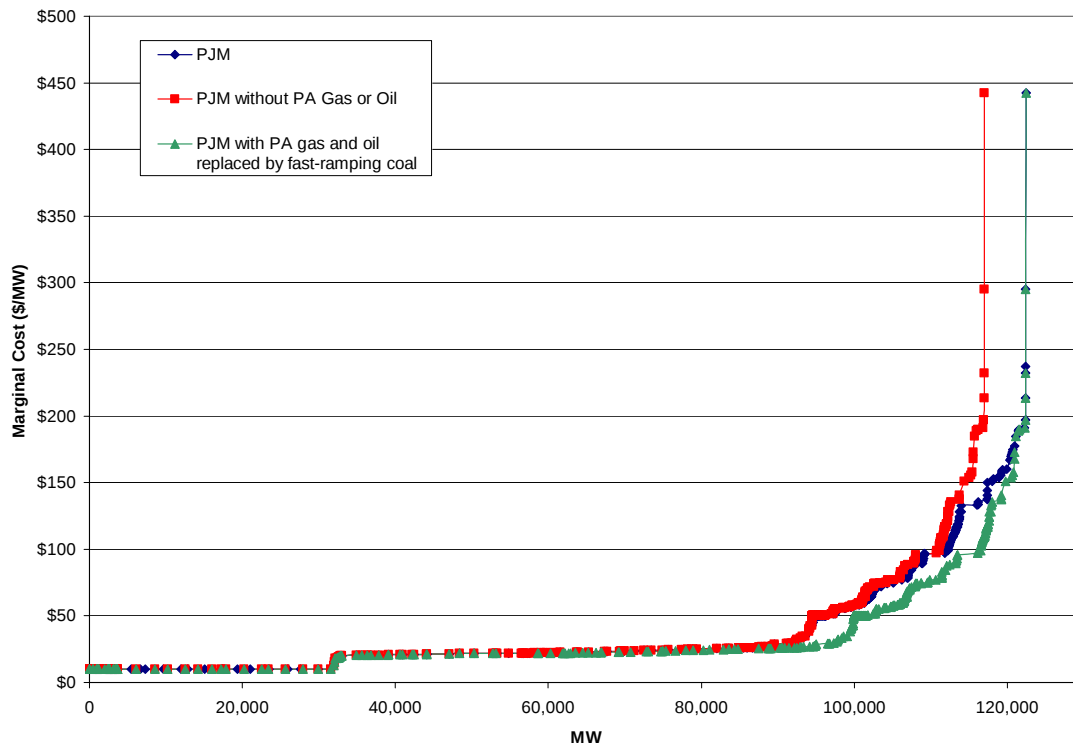


Figure 33. Marginal cost curves for PJM. One curve (blue) shows the marginal cost curve for PJM as it currently exists. The other curves show what the marginal cost curve would be if Pennsylvania stopped generating electricity from oil and gas (red); and if the existing oil and gas was replaced by fast-ramping coal-fired generation (green).

Pennsylvania cannot directly influence the generation mixes of other states in PJM or other RTOs. Figure 33 shows the effect on the PJM marginal cost curve due to natural gas and oil-fired units located in Pennsylvania. Using 2005 load data for PJM, we calculate a load-weighted average energy cost in PJM of \$45.15/MWh. The removal of Pennsylvania's gas and oil generation, if not replaced by other generation, would increase the average cost in PJM to \$51.62/MWh. The average cost increases with the removal of these expensive generation sources because even more expensive gas and oil generation (located outside of Pennsylvania) would need to be dispatched in its place.

One policy option that was suggested both in the written comments submitted to the Pennsylvania P.U.C. as part of their hearing on electricity prices and in our interviews of market participants was the establishment of a Pennsylvania public power authority similar to the New York Power Authority. This public agency would use Pennsylvania's good credit rating to obtain inexpensive financing for new generation sources, which would then be sold on an average-cost basis to targeted rate classes (the New York Power for Jobs program, for example, targets large industrial and commercial customers). Figure 33 demonstrates what would happen if the gas and oil generation in Pennsylvania were to be replaced by fast-ramping coal generation,⁴⁹ perhaps financed by something like a Pennsylvania power authority. If the generation was bid into the PJM spot market, such an investment program would lower the average cost of power in PJM to \$40.62/MWh, a decrease of approximately 0.5 cents per kWh from current rates.

3.1.2 Transmission congestion

Prior to restructuring, the transmission network existed as a vehicle for delivering power from a utility's generators to its load. Under restructuring and with the onset of centralized regional power markets like PJM, the transmission network must facilitate competition by allowing customers to receive power from any generator within the RTO. Thus, competition requires a very different kind of transmission network both in size and topology. Transmission investment has declined dramatically since the 1970s, although there was a small increase at the onset of restructuring, largely to support new generation interconnections.⁵⁰

Major transmission interconnections in PJM are loaded to capacity or "congested" a significant portion of the time. Figure 34 shows the distribution of hourly loading as a percent of the transfer limit for the Bedington-Black Oak line running from West Virginia to Maryland. As can be seen from the figure, the Bedington-Black Oak line was congested or nearly congested virtually every hour of the year in 2005.

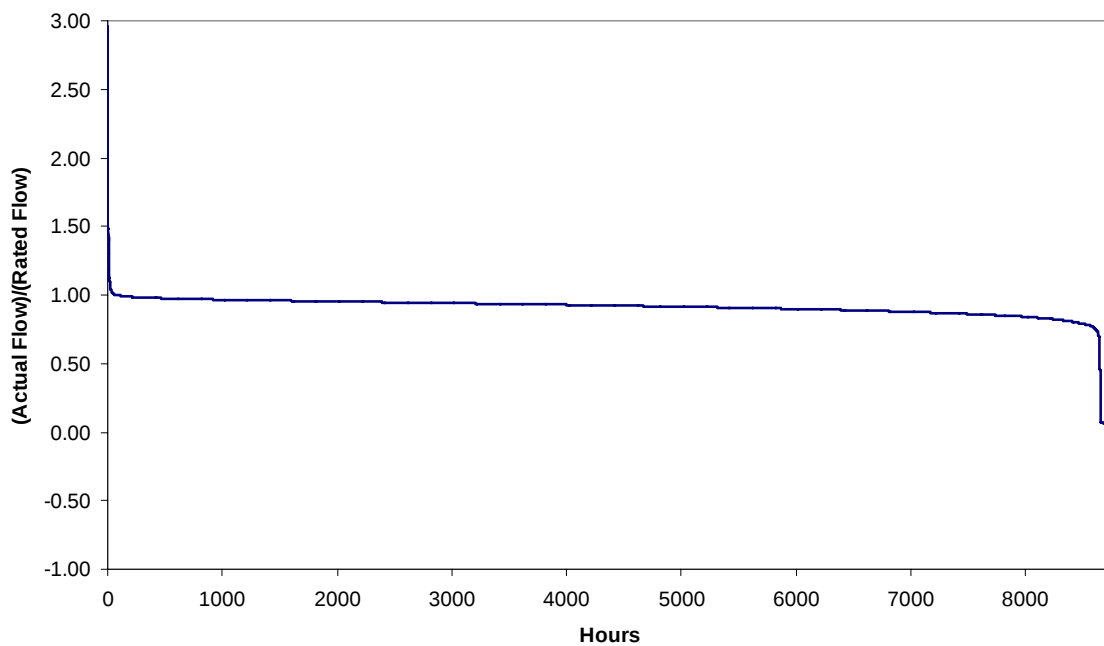


Figure 34. The ratio of actual flow to transfer capability along the Bedington-Black Oak line in PJM, 2005. Six hours where the transfer capability was equal to zero were dropped from the data set. Flows exceeding the transfer capability limit are allowable for short periods of time following contingencies elsewhere in the system. Negative flows indicate a change in direction of the flow. Source: PJM.

Transmission congestion prevents the lowest cost generators from serving the load, leading to pockets of high or low price, as shown in figure 8. Figure 35 shows the LMP difference over time between Pittsburgh and Philadelphia. The spread between the LMP in Pittsburgh and the LMP in Philadelphia can be taken as a measure of the amount of congestion between the two load centers.

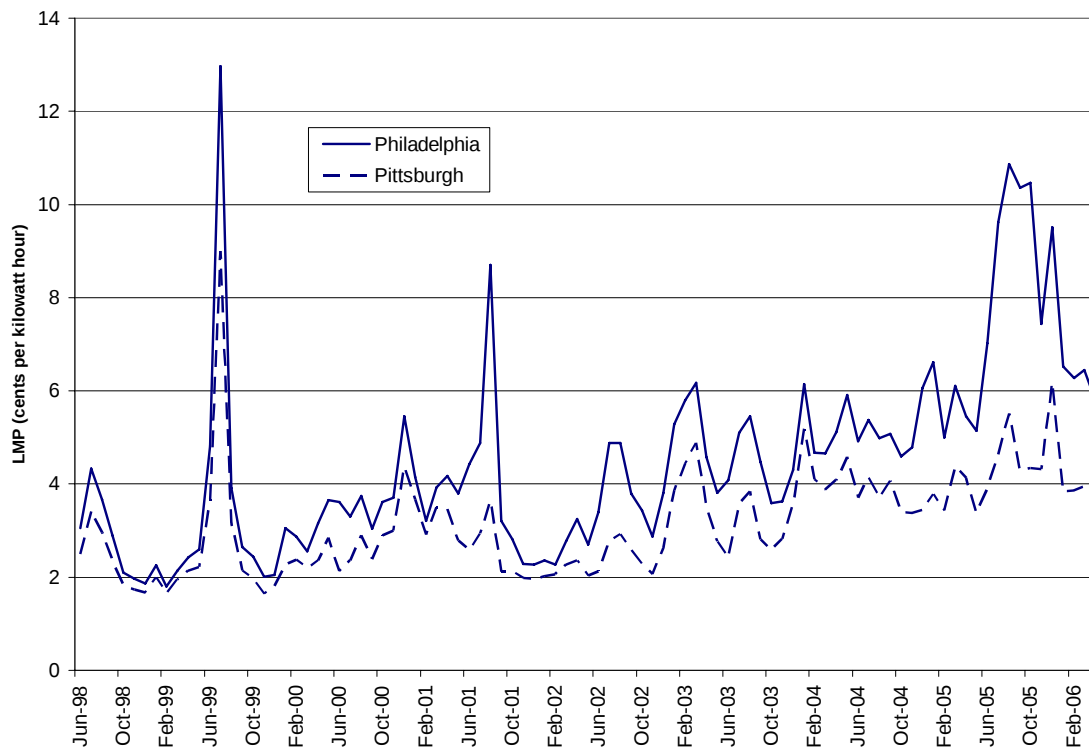


Figure 35. LMPs in Pittsburgh and Philadelphia. The Pittsburgh LMP is equal to the PJM Western Hub LMP prior to Duquesne Light joining PJM in January 2005. The Philadelphia LMP is equal to the PECO zonal LMP. Source: PJM.

Figure 35 shows that the congestion charge for moving a kilowatt of electricity between Pittsburgh and Philadelphia has increased over time. Congestion charges have been increasing in PJM since its inception. Table 12 shows the total annual congestion charges assessed on market participants, and the average annual congestion charge.

Year	PJM Congestion Costs	
	Total (\$M)	Average (\$/MWh)
1999	53	0.20
2000	132	0.50
2001	271	1.02
2002	430	1.37
2003	499	1.52
2004	750	1.71
2005	2,090	3.05

Table 12. Total and average annual congestion charges in PJM. Source: PJM State of the Market Report, various years.

The Bedington-Black Oak line is one of a few major west-to-east interconnections within PJM. The PJM Regional Transmission Expansion Plan (RTEP) has scheduled nearly every west-east transmission line for an upgrade of one sort or another.⁵¹ In addition, AEP has proposed building a major 765-kV project from its West Virginia coal facilities to the Philadelphia and New Jersey Area.⁵² In our interviews of Pennsylvania industry stakeholders, we were also told of a proposed transmission addition running from Western Pennsylvania to Washington, D.C. Siting transmission projects has

become increasingly difficult, and Pennsylvania has been cited as a location with a high demand for new transmission, but also a high degree of difficulty in getting needed investments built.⁵³ Over a decade ago there was a proposal to build a high capacity line across northern Pennsylvania to move power from Western Pennsylvania to customers in the east; it was defeated by siting opposition. The Energy Policy Act of 2005 contains a number of regulatory mechanisms aimed at shortening the siting process for transmission facilities deemed to be in the “national interest.”⁵⁴

While some uncertainty still remains regarding which proposed transmission projects will get built, the effect on the wholesale market will likely be a convergence of prices between Eastern and Western Pennsylvania. Prices in Eastern Pennsylvania will go down as more inexpensive generation can be transferred from west to east, and prices in Western Pennsylvania will likely increase as dispatch patterns shift and eastern demand for low-cost Western PJM generation increases. Market prices will not completely equalize unless the constraints are fully removed, but some degree of price convergence should be expected.

It is likely that any increase in the number or capacity of transmission lines leading from Pennsylvania to the high-priced markets to the south or east of the Commonwealth will tend to increase prices in Pennsylvania substantially.

In PJM, load serving utilities, generators, or marketers can purchase financial transmission rights in addition to simply buying energy from the PJM spot market. A financial transmission right for a particular node pair entitles the owner to collect the congestion payment for this node pair. If the node pair is in a heavily congested part of the network, the payments can be substantial. In effect, the FTRs entitle someone to ship power between the two nodes without paying for congestion. When it took over the grid, PJM awarded FTRs to load serving entities that owned transmission between their generators and customers. The FTRs meant that the LSE would not have to worry about congestion costs in shipping power from their generators to their customers. PJM also creates a market for FTR to allow customers or generators to hedge against congestion costs in negotiating a contract between a particular generator and customer. Finally, FTRs can be awarded to whoever builds a new transmission line in payment for creating this new capacity.

3.1.3 Capacity markets in PJM

In PJM, load serving utilities or marketers must purchase capacity rights in addition to simply buying energy from the PJM spot market. Capacity can be self-supplied through generation ownership, it can be purchased bilaterally, or it can be purchased through PJM’s centralized auction for capacity rights. PJM sells capacity rights over a variety of time periods, from daily to multiple-month capacity rights. Other RTOs have a similar mechanism for purchasing capacity rights. Texas (which is not subject to FERC jurisdiction) does not have any kind of capacity market.

Capacity markets arose for reliability reasons (ensuring that each load serving entity had enough capacity in reserve to fill demand) and as a way to promote investment, particularly in peaking generation. Since RTOs have price caps and strict market mitigation protocols for their electric energy spot markets, prices far above marginal costs are not commonplace. However, generators (which under regulation received average cost payments) rely on earning some return beyond marginal cost in order to recoup capital investment costs. If generators (particularly peakers) face strict bidding restrictions in terms of price, there may be no incentive for new generation investment. Capacity markets try to solve this problem by introducing another revenue source for generators. Part of the controversy surrounds the fact that both installed and new capacity can receive capacity payments. This amounts to extra profit for many coal and nuclear plants, whose capital costs are long since fully depreciated (or whose owners are allowed to recover stranded costs, as is the case in Pennsylvania).

The capacity payments increase prices to consumers. Further, PJM acknowledges that the potential for capacity-market manipulation is high. PJM writes that in 2005, its capacity markets were “reasonably” to “highly” uncompetitive during peak times of the year.⁵⁵

PJM has recognized that its current capacity market is failing to provide sufficient financial incentives to encourage investments in new generation necessary to ensure reliability. To remedy this, PJM has proposed a new capacity market component, the Reliability Pricing Model (RPM), designed to provide incentives for capacity in areas that need it most through a locational pricing component and downward sloping demand curve. The structure of RPM is similar to the Locational Installed Capacity (LICAP) market currently in place in ISO New England. While the details of the RPM are still being finalized by PJM and FERC there is consensus that the RPM will provide additional payments to existing capacity in constrained areas and possibly to existing capacity in unconstrained areas as well. Furthermore, RPM allows newer coal, oil, and natural gas facilities to include the costs of environmental controls, up to \$200/kW in their offer bids. Very old fossil-fuel facilities have no limit on what they can include in their offer bids under RPM.

3.2 Costs of Pennsylvania's Alternative Energy Portfolio Standard (AEPS)

At the time that rate caps expire in the majority of Pennsylvania, the AEPS will not change electricity costs significantly, and the AEPS helps by providing incentives for new generation. The subsidy for plants burning waste coal will probably lower electricity prices slightly while the mandate for 800 megawatts (MW) of solar photovoltaic power will raise prices after 2015 above what the price would be if the power were supplied by another renewable source, wind energy, unless solar costs fall significantly compared to wind. The Commonwealth should continue to monitor the costs of solar photovoltaic power as the large-scale implementation deadline approaches.

The Pennsylvania Alternative Energy Portfolio Standards Act (herein after referred to as “Act 213” or “the Act”),⁵⁶ which was signed into law on November 30, 2004, and took effect ninety days thereafter on February 28, 2005, ensures that 18 percent of all retail energy generated by 2021 will come from clean, efficient and advanced resources. The Act establishes a fifteen-year schedule for complying with its mandates and utilizes a two tier systems to ensure that the state’s electricity needs are met by introducing advanced and renewable resources. The percentage of Tier I and Tier II alternative energy sources that must be included in sales to retail customers gradually increases over this period. The Act mandates that electric distribution companies and electric generation companies, to the extent that compliance is not otherwise exempted, must begin to include alternative energy sources from Tier I in their sales to retail customers no later than February 28, 2007.

Tier I requires 8 percent of electricity sold at retail in the Commonwealth to come from renewable sources such as solar photovoltaic energy, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy or coal-mine methane. At least 0.5 percent of the Tier I electricity must come from solar photovoltaics. Tier II requires 10 percent of the electricity to be generated from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from pulping and wood manufacturing byproducts, and integrated combined cycle coal gasification technology.

Subsection 3(b)(1) of the Act provides that two years after the effective date of the Act, at least 1.5% of the electricity sold by an electric distribution company or electric generation supplier to retail customers in the Commonwealth must be generated from Tier I alternative energy sources. Except as otherwise specified in the Act, Tier I alternative energy sources must represent 2% of electric energy sales after three years, and at least 8% of electric energy sales by the fifteenth year. Years 16 and thereafter use the Tier I, Tier II and solar photovoltaic compliance thresholds in effect for Year 15.

The rationale for the Tier II generation is largely to solve environmental problems. A new waste coal plant is somewhat more costly than a new coal plant, but the difference is small and a major environmental problem is solved. With the subsidy, a waste coal plant is likely to have lower costs than a new coal plant. Adding low cost capacity is likely to slightly lower the market price of electricity.

The Tier I standards are designed to encourage bringing new technology into the market. At good wind sites, the first increments of wind power can be cost-competitive with other generation sources. The same is true of coal mine methane. Biologically derived methane is not yet a commercial technology and its potential costs and capacity are unknown. In contrast, solar photovoltaic is a known commercial technology whose costs are much greater than that of competitive technologies.

Of the electric energy required to be sold from Tier I sources, the total percentage that must be sold from solar photovoltaic technologies is 0.0013% for years 1 through 4; 0.0203% for years 10 through 14; 0.25% for years 10 through 14; and 0.5% for year 15 and thereafter. Under this fifteen-year schedule, utilities will be required to purchase approximately 800 megawatts of solar photovoltaic-produced electricity by 2021. The solar PV requirement in megawatts (using the PJM load forecast) per year from 2006 through 2021 is represented in figure 36.

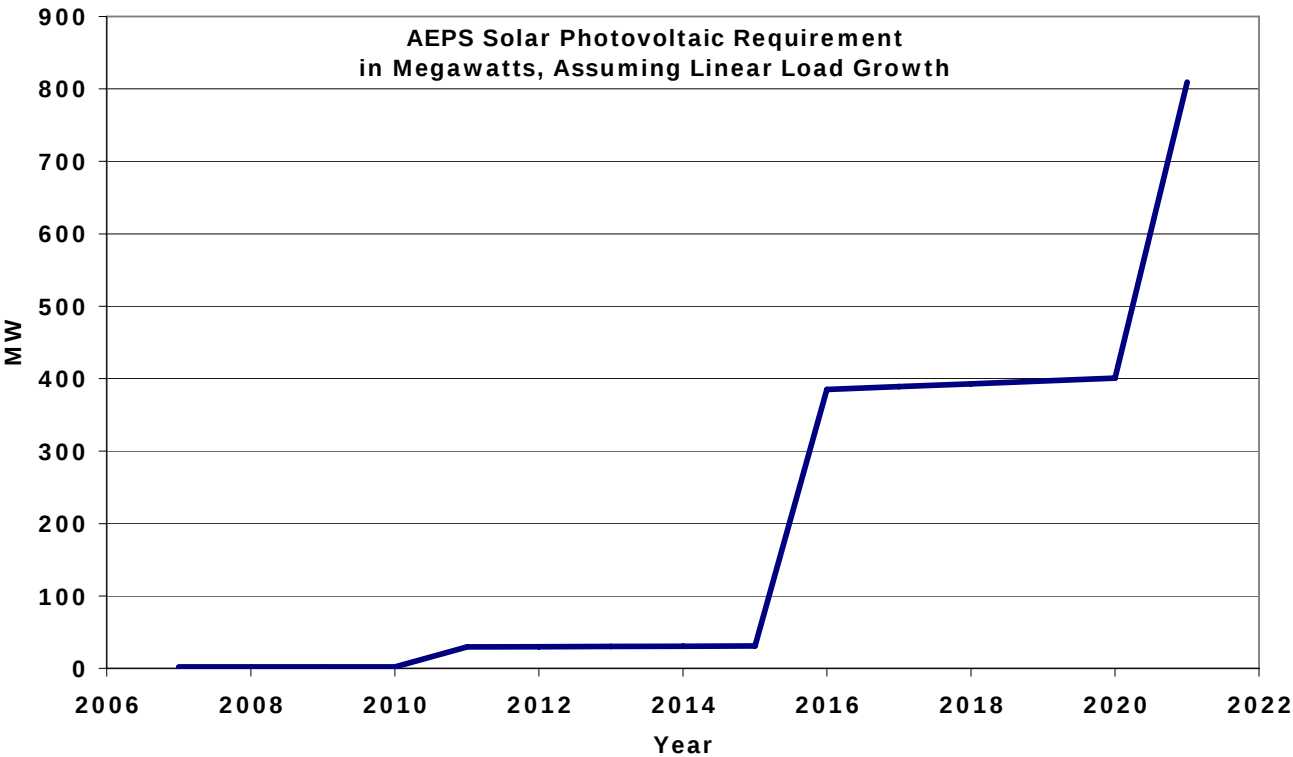


Figure 36. Pennsylvania AEPS solar photovoltaic requirement in MW.

An inherent limitation of the Tier I intermittent sources (wind and solar photovoltaic power) is that they are not available on demand. If the wind doesn't blow or the sun doesn't shine when power is needed, backup generation must be available. At a good Pennsylvania site, a wind turbine will generate power about 25% of the time and a solar PV array will generate power about 15% of the time. Thus, unless inexpensive ways are found to store electricity, these intermediate sources will not lower the need for reliable generation capacity. An additional concern with these intermittent sources is the variability in output as wind speed changes or clouds obscure the sun. To maintain power quality, other sources must counterbalance the generation fluctuations. This service is termed "regulation." The cost of supplying regulation for these intermediate sources in PJM was a concern expressed in several of the interviews conducted for this study. Regulation accounts for approximately 0.2 cents per kWh in PJM,

so the Tier I sources are unlikely to increase consumer costs greatly, but this cost will increase as the intermediate sources generate a larger proportion of electricity. Calculation of the effects of intermittent generation sources on regulation price within PJM nodes in Pennsylvania should be commissioned with the cooperation of PJM to fully estimate the effects on consumer prices.

3.3 Regulatory and tax effects

3.3.1 Competitive Transition Charge

Pennsylvania's distribution utilities have been allowed to recoup stranded generation costs and other costs incurred during the transition period to full retail competition. Utilities are allowed to recover these costs through a competitive transition charge (CTC) and an intangible transition charge (ITC).⁵⁷ The allowable recoverable costs include the costs associated with issuing transition bonds to retire debt from generation assets that would hamper the ability of the utility to compete effectively for retail customers. In some states, the competitive transition charge also acts as an insurance policy for the default service provider, reimbursing the utility for deviations between actual default service load and the amount of generation under contract by the utility to serve default customers. Stranded cost allowances and the associated charges were agreed to between each utility and the Pennsylvania P.U.C.; there is no single statewide stranded cost allowance.

Duquesne Light Stranded Costs

Duquesne Light retired its stranded costs in 2004; therefore, Duquesne customers no longer pay competitive transition charges.

West Penn (Allegheny)

West Penn (Allegheny) does not charge its customers a competitive transition charge, but does have an intangible transition charge. For industrial and large commercial customers, the intangible transition charge has a declining-block demand portion ranging from 64.7 cents/kW to 65.5 cents/kW and a declining-block energy portion ranging from 0.195 cents/kWh to 0.201 cents/kWh. For smaller commercial customers, the intangible transition charge has a declining-block demand portion ranging from 53 cents/kW to 68 cents/kW and a declining-block energy portion ranging from 0.391 cents/kWh and 0.437 cents/kWh.

Penn Power

For large industrial and commercial customers with high-voltage service, Penn Power has a competitive transition charge with a declining-block energy charge of 59.3 cents/kW to 88.5 cents/kW and a declining-block energy charge of 0.27 cents/kWh to 0.53 cents/kWh. For medium industrial customers and commercial customers, Penn Power's competitive transition charge consists of a single demand portion, between 64.4 cents/kW and 65.9 cents/kW depending on the customer voltage, and a declining-block energy portion between 0.259 cents/kWh and 0.493 cents/kWh. For small commercial customers, Penn Power's competitive transition charge consists of a single demand portion of 75 cents/kW and a declining-block energy portion between 0.269 and 0.562 cents/kWh.

PPL

PPL has both a competitive transition charge and an intangible transition charge. For large commercial and industrial customers, the competitive transition charge has a demand component ranging from 18.7 cents/kW to 23.8 cents/kW (depending on customer voltage), rising to between 80.9 cents/kW to \$1.06/kW in 2009. The declining-block energy component of the large-customer competitive transition charge currently ranges from 0.082 cents/kWh to 0.286 cents/kWh, but will increase to between 0.435 cents/kWh and 0.682 cents/kWh. The current intangible transition charge for large commercial and industrial customers has a demand component ranging from 76 cents/kWh to 98.2

cents/kWh (depending on customer voltage) and a declining-block energy component between 0.4 cents/kWh and 0.948 cents/kWh. The intangible transition charge will be eliminated in 2009. For small non-residential customers, PPL's competitive transition charge currently does not have a demand portion, but does have a declining-block energy portion of between 0.211 cents/kWh and 0.281 cents/kWh, rising to between 1.115 cents/kWh and 1.484 cents/kWh by 2009. PPL's intangible transition charge for small customers currently has a declining-block energy portion between 1.035 cents/kWh and 1.377 cents/kWh. The intangible transition charge for small customers will be eliminated in 2009.

PECO

For large industrial customers at high voltages, PECO's competitive transition charge has a demand component equal to \$4.74 per kW, and a declining-block energy portion between 0.56 cents/kWh and 2.62 cents/kWh. For commercial and industrial customers at lower voltages, PECO's competitive transition charge has no demand component, but does have a declining-block energy portion between 1.03 cents/kWh and 7.28 cents/kWh.

Summary of stranded cost recovery impacts

The impact of stranded cost recovery thus varies widely among utilities in Pennsylvania. For industrial customers in the West Penn (Allegheny) territory taking default service from the distribution utility, stranded costs amount to less than 5% of the average industrial rate. In PECO's territory, on the other hand, stranded costs could amount to 25% of the industrial rate. Particularly in PECO, stranded costs appear to account for much of the difference between the utility's industrial rate and the LMP in its service territory, as shown in figure 31.

3.3.2 Pollution control costs

In our interviews of Pennsylvania electric market stakeholders, several participants reflected that the high cost of Pennsylvania's strict environmental controls represents a competitive disadvantage for the Commonwealth. Other states that do not impose strict pollution controls on the production of electricity, like West Virginia and Kentucky, can offer less-expensive rates to commercial and industrial consumers. While it is unlikely that industrials will move their operations to these states (due to the large capital and labor costs that would be involved), to the extent that environmental controls increase retail electricity prices, this might influence locational expansion decisions of certain companies. Some of our interview participants told us that electricity prices affect how scarce intra-firm capital is allocated.

While there are some small and fundamental cost differences between Pennsylvania and surrounding lower-cost states, environmental costs are unlikely to remain a significant factor. There are several reasons to believe that any cost disadvantage due to environmental laws in Pennsylvania will disappear within the next several years. The Clean Air Interstate Rule (CAIR), issued in March 2005, will introduce a cap and trade system for the emission of sulfur dioxide (SO₂) and nitrogen oxides (NO_x).⁵⁸ Virtually every eastern U.S. state is affected by CAIR; coal-fired power plants will either need to install pollution-control devices or purchase emissions credits in the market. Thus, the cost of generating electricity from coal should be expected to rise substantially in states that have not yet installed stringent pollution controls. Potential future regulations (within the next ten to fifteen years) include controls on mercury and carbon.

Some of these regulations (particularly carbon control) could actually give Pennsylvania a cost advantage; 37% of the electricity generated in Pennsylvania is from carbon-free nuclear power, while West Virginia and Kentucky have none. Full carbon controls could add 2 - 5 cents per kWh to the cost of coal generation. Thus, the combination of CAIR and carbon regulations could give Pennsylvania an electricity cost advantage over Kentucky and West Virginia. The Allegheny Conference report estimated

that 3P (NO_x, SO₂, and mercury) control would raise costs in Kentucky by approximately 1 cent per kWh..

3.3.3 Gross Receipts Tax in Pennsylvania and other states

Pennsylvania charges a Gross Receipts Tax of 59 mills (5.9%) on all power sold to an end-use consumer within the Commonwealth (wholesale transactions between generators and load serving entities are not subject to the tax). The relevant language can be found in 72 Pa. C.S. §8101(b)(1). Electricity generated in Pennsylvania and sold to another state is subject to the Gross Receipts Tax if a similar tax is imposed by that state on power generated in that state and sold into Pennsylvania. The relevant language can be found in 2 Pa. C.S. §8101(b)(2). While the Gross Receipts Tax specified in 2 Pa. C.S. §8101(b)(1) is well known and is mentioned in Pennsylvania utility tariffs, the Gross Receipts Tax specified in 2 Pa. C.S. §8101(b)(2) appears not to be as well known. In our interviews of Pennsylvania stakeholders, we encountered very few participants who were aware of this second Gross Receipts Tax.

The Allegheny Conference report recommended repealing the Gross Receipts Tax on the sale of electricity to industrial consumers. For industrial customers in the Duquesne Light territory, the Gross Receipts Tax amounts to 0.43 cents per kWh.⁵⁹ In addition to Pennsylvania, several surrounding states impose Gross Receipts Taxes on the sale of electricity (these taxes are also assessed at the point of consumption rather than the point of production). Maryland's Gross Receipts Tax is 2%, and West Virginia's Gross Receipts Tax is administered by municipalities rather than by the state. These taxes generally range from 2% to 4%, although they do get as low as 0.6%. Some West Virginia municipalities tax industrial service at a lower rate than commercial or residential service. Ohio does not have a Gross Receipts Tax, but does have an explicit tax on the consumption of electricity. Ohio's tax has a declining block structure; the first 2,000 kWh is subject to a tax of 0.465 cents per kWh, the next 13,000 kWh is taxed at 0.419 cents per kWh, and consumption over 15,000 kWh is taxed at 0.363 cents per kWh. Thus, while Pennsylvania's Gross Receipts Tax is higher than similar taxes in surrounding states, the differences are generally not large.

We estimate that the revenue loss to the Commonwealth would be \$730 million for all customers, or \$465 million if the Gross Receipts Tax were to be lifted on all commercial and industrial customers, and less if targeted economic development exemptions were used.

3.3.4 Costs of using the market

In addition to some of the indirect ways in which the structure of RTO markets can raise costs, there are direct costs associated with establishing, running, and monitoring the market. These are shown on a total and average basis in figures 37 and 38. The administrative costs of RTO markets have been rising over time, both in total and on average. The Allegheny Conference report mentioned that ISOs and RTOs are under pressure to reduce costs. While these costs are reflected in higher wholesale and retail prices, they are generally not substantial, seldom amounting to more than 0.1 cents per kWh transacted. PJM has the lowest average costs of any U.S. RTO.

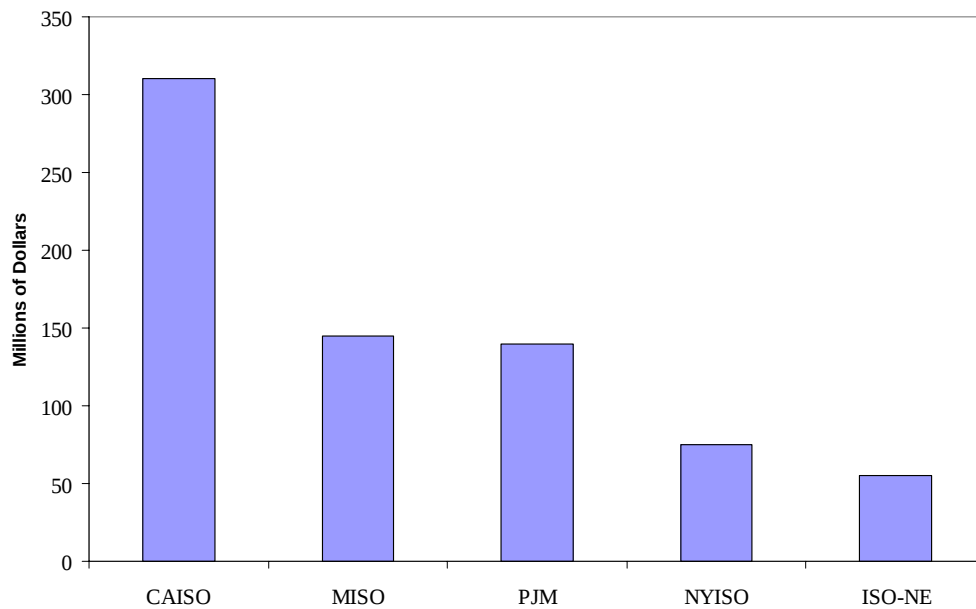


Figure 37. ISO and RTO start-up costs. Source: Public Power Council, "A Comparative Analysis of ISO/RTO Operating Costs," 2004.

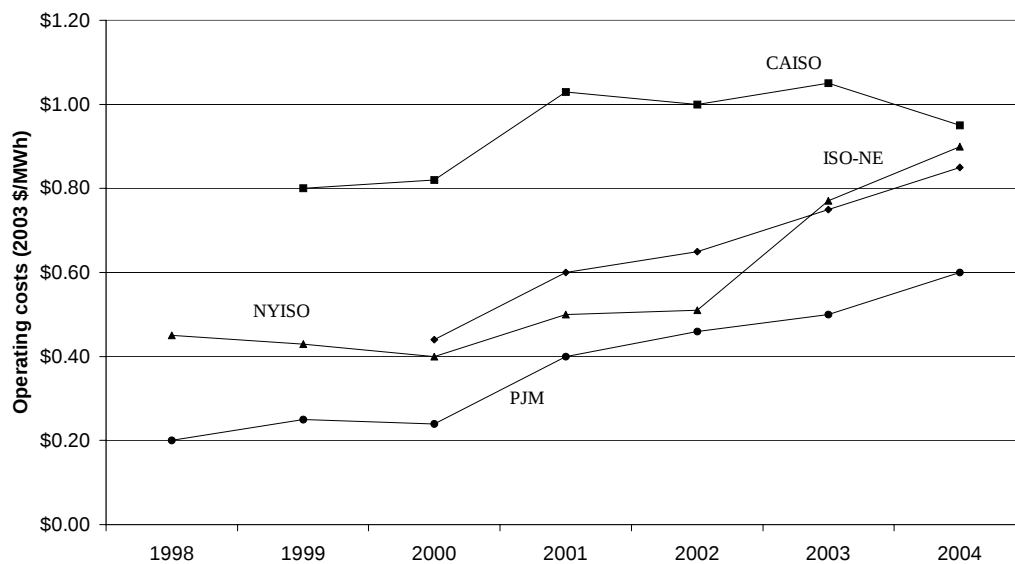


Figure 38. ISO and RTO operating costs. Source: Public Power Council, "A Comparative Analysis of ISO/RTO Operating Costs," 2004.

In our interviews, market participants generally reported low barriers to entry and direct costs of joining PJM and being allowed to trade in its markets. Simply joining PJM costs \$5,000, but trading in PJM requires a letter of credit amounting to several hundred thousand dollars (exact figures were not made available to us; these likely vary depending on the size of the market position taken by each individual trading operation). Competing effectively requires hiring extra personnel, gathering data, and investing in equipment and specialized software. Interview participants were generally unwilling to disclose their expenditures to trade in PJM or other RTO markets, but reported annual expenditures of tens of millions of dollars were common. Market participants will need to recover these costs in some form.

4. TECHNICAL, MARKET and REGULATORY OPTIONS ANALYSIS

We have identified and analyzed policy options available for competitive energy pricing in the Commonwealth. The largest savings for commercial and industrial customers are obtained through self-generation and overall net demand reduction. Programs designed to reduce demand (including real time pricing) can lower prices at approximately the same time rate caps expire. To continue those savings as the economy of the Commonwealth grows, new plants should be brought online with available mechanisms which preserve competition but do not perpetuate the current way their output is bid into the hourly auctions. Options for rapid action also are at hand, including modifications to the gross receipts tax, POLR switching requirements, and targeted allocation of transmission rights. A reasonable portfolio of these options can plausibly offset rate increases as large as 60% for commercial customers and 35% for industrial customers. Larger savings are possible for targeted customers. An option to stabilize or reduce the price of natural gas in the Commonwealth is also feasible, and is being implemented in another state.

4.1 Options to reduce locational marginal prices (LMPs)

The uniform price auction model applied in PJM and other markets means that prices in a particular hour are set by the highest cost unit required to meet demand. Our calculation shown in figure 32 suggests that natural gas set the market clearing price in at least part of 75% of all hours in 2005. By bringing more low cost generation into the market or lowering demand, Pennsylvania could lower the number of hours that gas or oil units set market price, thus lowering the market clearing price.

4.1.1 Keep existing low cost generation

Some of those interviewed for this study felt that stringent 3P (NO_x, SO₂, and mercury) emissions standards could drive some low-cost generators to close. Evaluating the total cost of 3P control to consumers must properly consider both the direct costs of any necessary investments, plus the effects of removing some low-cost generation from the PJM dispatch order, which would increase the number of hours high cost gas and/or oil set the market clearing price. A benefit-cost analysis for regulations would consider the dispatch implications. Thus, policies that encourage existing low-cost generation sources to continue operating, even when expensive environmental controls are required, could lower costs to industrial and commercial customers of all classes in the Commonwealth significantly.

There is a clear social benefit to producing power with low environmental impact. The Commonwealth might explore direct environmental capital cost reimbursement payments to generators through a wires charge (without a rate of return) to keep these plants economically viable after installation of environmental controls and so that their bids reflect fuel costs. It is possible that it may be beneficial to offer the same inducement to newly constructed plants, but that option requires further analysis.

The Commonwealth produces over a third of its electricity from nuclear plants, whose operating costs are among the lowest in the state. Pennsylvania should encourage its existing nuclear facilities to continue to increase capacity where possible (through steam turbine upgrades as applicable) and maintain their excellent availability. If new nuclear facilities are available at competitive costs, they may be attractive as new baseload generators in the state, although we note that there is fuel price risk for nuclear fuel, as the uranium price spikes of 1974 – 1983 demonstrated.

4.1.2 Use Pennsylvania's coal resources to best advantage

The cost to ship coal by rail and barge has increased in the past few years. The savings at West Virginia and Kentucky mine-mouth electricity generating plants is approximately 0.4 cent per kWh.

Increasing the number of rail and barge companies competing for transportation business could reduce Pennsylvania's transportation-cost disadvantage significantly.

Pennsylvania has abundant reserves of coal, and use of those reserves near coal generators should be encouraged. At the October 20, 2006 "Energy Summit 2006: Generating Ideas for Southwestern Pennsylvania", CONSOL Energy stated that it takes six to seven years to acquire the permits for new mines in Pennsylvania. It is clearly in the interest of the Commonwealth to examine whether this is the case, and to reduce the barriers to entry of new mines, consistent with environmental goals and safety.

4.1.3 Encourage new generation to locate close to load

Eastern Pennsylvania has high prices in part because demand for electricity exceeds local supply. Transmission lines are expensive and controversial, and some power is lost due to electrical resistance in the lines. Incentives in the form of expedited permitting and other non-monetary inducements for low cost generators seeking to locate near load should be explored, consistent with environmental goals and safety. Transmission line congestion charges in PJM amounted to \$2.1 billion, or 9% of the total PJM billings in 2005.⁶⁰ If all new generation were to locate close to load in Pennsylvania over the next decade, prices might decrease by 1%. Conversely, if new generation is located far from load, prices would increase by several percent.

4.1.4 Real time pricing

Demand for electricity in PJM is variable (figure 9). The generating units needed to meet peak demands have much higher costs than baseload generators (which run for a large number of hours).

Baseload power is supplied by efficient units whose capital cost is spread over a very large number of operating hours, so they can supply power at a cost of \$30 per MWh or less. There are roughly 90,000 MW (90 GW) of such plants in PJM. When demand exceeds 90 GW, more expensive plants must be used. An estimate of the marginal cost of all the generation plants in PJM operating in 2002 is shown below in figure 39.⁶¹ Comparison to the load curves in figure 9 shows that meeting peak demand on a winter afternoon (110 GW) would cost \$100 per MWh (10 cents per kWh), but would be \$30 per MWh (3 cents per kWh) at 6 AM on the same day.

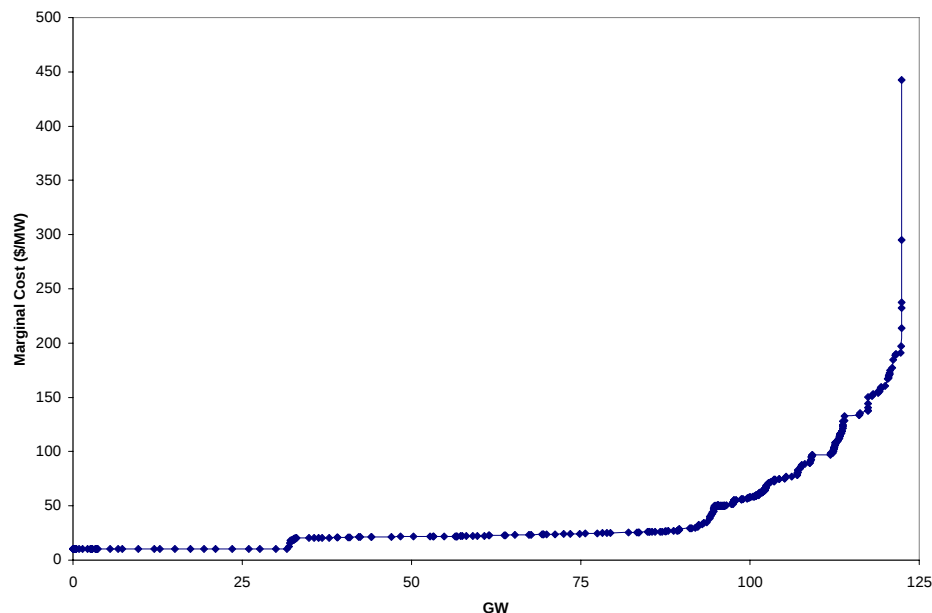


Figure 39. The marginal operating cost of generation as a function of total load in PJM.
Data based on 2002 EPA eGrid plant inventory and heat rate.

The most efficient use of resources occurs when consumers pay the marginal cost of producing each good or service. This is not the case for a large number of consumers in Pennsylvania. 95% of customers in PJM pay a price for power averaged over all hours in a day and over many days.

If customers were to pay the actual price of power generation at peak times (which can exceed \$2 per kWh), they would use less power. Conversely, if they were to pay the actual price of power generation late at night or very early in the morning, they might use more when the price was low. Since the marginal cost curve for PJM becomes very steep during peak demand periods (as shown in figure 39), small amounts of demand response can have significant effects on market prices. Even if only a minority of consumers responded to the changing prices, other consumers in the system would benefit through the reduced need for peaking generators and lower cost and price.

We have used PJM data from June 2005 through May 2006 to examine the effect of real time pricing on average prices in PJM (figure 40a), under a wide variety of assumptions about consumer behavior, from no reduction of demand when price changes (completely inelastic) to a 50% reduction in demand for a doubling of price (elasticity of -1).⁶²

We find that the maximum amount of response to real time pricing leads to an average price reduction of 6%, less the cost of the special electric meters required to implement the program. As more demand responds to real time pricing (elasticity less than -0.3), the average price increases slightly, since demand rises more in the low price hours than it falls in the high price hours (figure 41). Customers respond to the lower average price by slightly increasing their overall consumption of electricity (figure 40b).

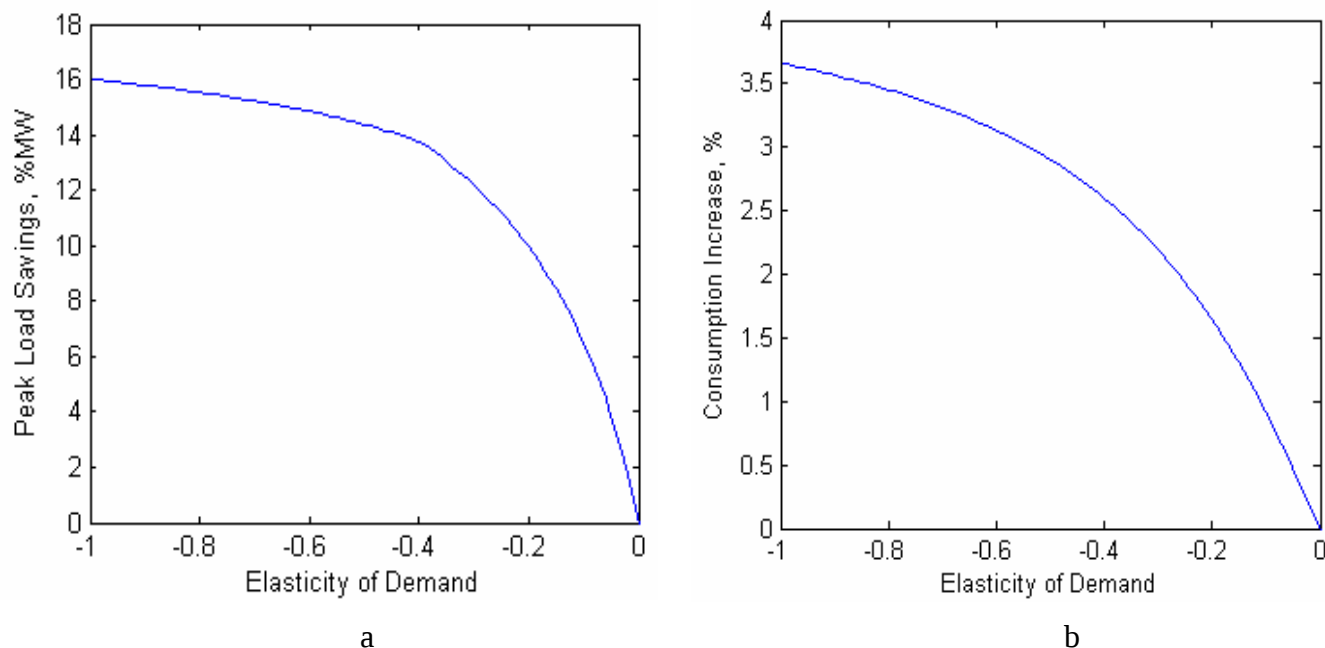


Figure 40. (a) Percent of peak load savings in PJM for a range of demand response to prices (elasticity). An elasticity of demand of zero represents no reduction of demand when price changes (inelastic). An elasticity of demand of -1 represents a 50% reduction in demand for a doubling of price. (b) Increase in total demand, due to lower average price of electricity.

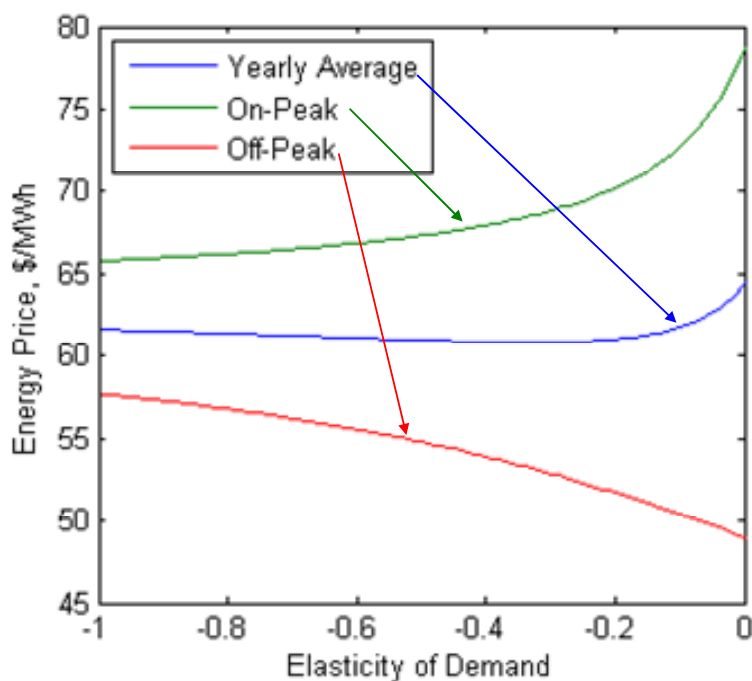


Figure 41. Effect of real time pricing on average prices in PJM for a range of demand response to prices (elasticity).

We find that real time pricing leads consumers to buy more energy in low priced hours increasing total demand. The increased use in off-peak hours is a benefit to consumers and the economy, just as is the reduction in price in peak hours.

If Pennsylvania were to implement real time pricing with meters for the 5 million customers in the state, with meter costs similar to those in recent large meter purchases, the capital cost to ratepayers through load serving entities would be \$1.3 billion. Under the assumption that half the theoretical average price reduction is achieved, and the meters are amortized over 20 years, the average price reduction after allowing for the cost of the meters would be \$230 million per year, or 2% of in-state electricity sales.⁶³

A program focused on achieving a good benefit-to-cost ratio might concentrate on commercial and industrial users, who comprise 10% of the meters⁶⁴ but 64% of the load. If only 500,000 meters were purchased, but the total demand response in MW was the same, the net savings would be 3%, or \$350 million annually. Average savings to all commercial and industrial customers would be 0.2 – 0.3 cents per kWh plus the value of the additional electricity purchased at off-peak prices for those customers who shift their use to off-peak periods.

4.1.5 Market-based demand response programs

An economic demand response program was permanently integrated into the PJM energy market in 2005 and is designed to provide an incentive to customers or load aggregators to reduce demand when PJM LMPs are high. All five operating RTOs have such programs, although their details differ.⁶⁵ In PJM's program, called "economic demand response," a customer can bid load-reduction directly into the day-ahead energy market (a mechanism also exists to participate in the real time market).

Not all those enrolled in the economic demand response program actually participate. Based on recent data released by PJM, only 350-475 MW of PJM's 120,000 MW average summer load (less than 0.4%) was shed in 2005 as a result of high prices for customers participating in this program.⁶⁶ PJM data indicate that the enrollment in the economic demand response program is close to 2,000 MW (1.7% of total load). FERC has recommended a goal of at least 5% (7,250 MW) participation. This level of

market-based demand response can help achieve the maximum theoretical reduction discussed in the previous section, and should be encouraged.

Current payments for economic demand response in PJM are based on the LMP. When the LMP is greater than or equal to \$75/MWh, a customer whose demand response bid is accepted gets paid the full day ahead LMP, for each MWh of curtailed demand. If the LMP is less than \$75, the payment is equal to the difference between the LMP and the retail rate (including generation and transmission charges). Similar incentives exist for the real time market.

PJM rules prohibit customers who choose real time pricing from joining the economic demand response program. There is a clear social benefit if customers are allowed to participate in both programs, since shifting more load from the peak helps to achieve the maximum reduction.

A proposed modification to the PJM demand response rules would give all economic demand response participants a payment equal to the difference between the LMP and the generation portion of their retail rate for reducing their load, with no added payment for prices above \$75/MWh. This rule change could significantly reduce the opportunities for economic demand response, since customers would have less incentive to reduce load for prices above \$75/MWh. For example, if a customer has a generation charge of \$50/MWh, then to receive the same payment from PJM's proposed modified economic demand response program as under the existing program, the customer would have to increase its bid price for economic demand response by \$50/MWh. Thus a customer offering economic demand response resources at \$75/MWh would have to offer them at \$125/MWh to receive the same payment as under the present rules.

In 2005, the average PJM LMP was at or above \$75 during 15% of the hours. The average PJM LMP was at or above \$125 in only 5% of the hours. Thus, the proposed change to PJM's economic demand response program would result in much lower expected value for an economic demand response provider.

The proposed change in the PJM rules should be opposed by the Commonwealth, since it would lead to reduced opportunities for demand response, and higher peak and average prices.

The following options would increase participation in the economic demand response program: an education program targeted to commercial and industrial customers to make them aware of the economic demand response program and to reduce their transaction costs; removing uncertainty about the demand response program incentives by making both the program and the rules more permanent than they are at present; retaining the \$75/MWh trigger price for the economic demand response program (as is done in the New York ISO); and permitting real time price customers from participating in the economic demand response program.

4.1.6 Demand reduction programs

Beginning in the energy crises a generation ago, utilities were required to help customers reduce their demand for electricity. The cost-effectiveness of these programs has been mixed, in part because of mandates to achieve equity goals such as low income housing winterization. However, where programs have focused on saving energy at lowest cost, the results have been attractive financially.⁶⁷ Such reductions can reduce rates for all customers by reducing the number of hours expensive peaking plants are required, and hence set the market clearing price.

States such as California have achieved good demand reduction results at costs said to be below wholesale generation costs. The Efficiency Vermont program⁶⁸ is said to have achieved reductions of 7% of total load at a cost of 4 cents per kWh.⁶⁹ Supply curves developed by the Electric Power Research Institute (EPRI) and Global Energy Partners, LLC indicate that substantial peak use savings are achievable,⁷⁰ at costs of 15 cents per kWh (\$150 per MWh) and above (figure 42). Average demand

reduction savings at costs less than 5 cents per kWh (\$50 per MWh) were also found to be achievable (figure 43). These figures are for the nation as a whole. National peak load is expected to be 950 gigawatts (GW) in 2010, and national total electric energy use is expected to be approximately 4,000 terawatt-hours (TWh).

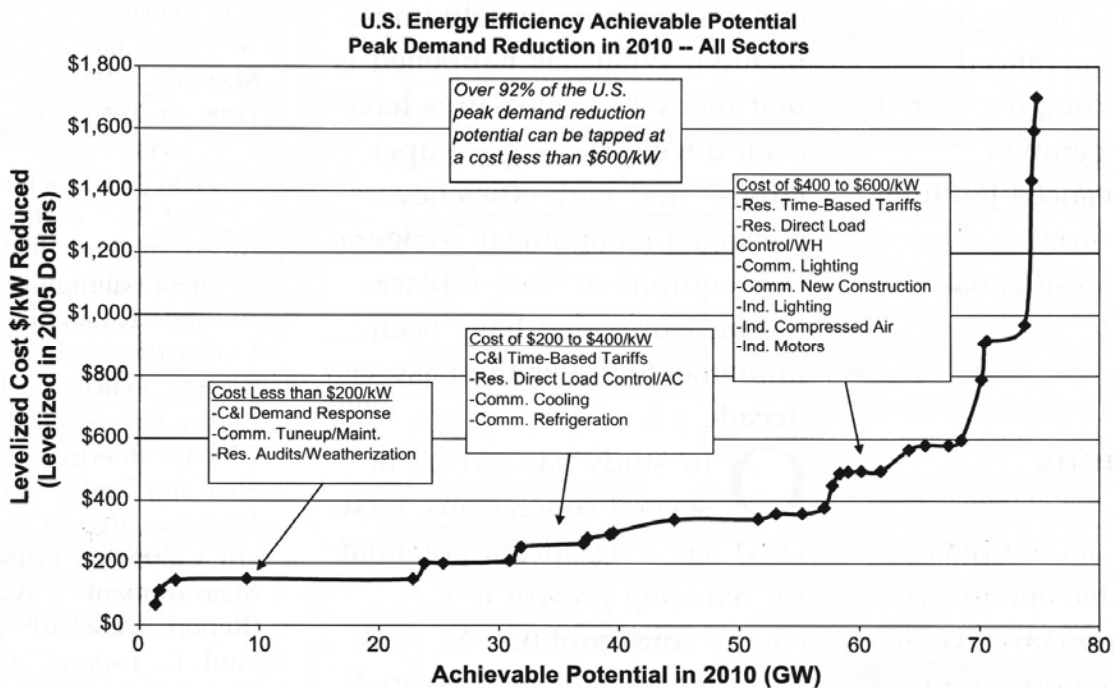


Figure 42. Supply curve for national peak demand savings in 2010 from Gellings et al.⁷⁰

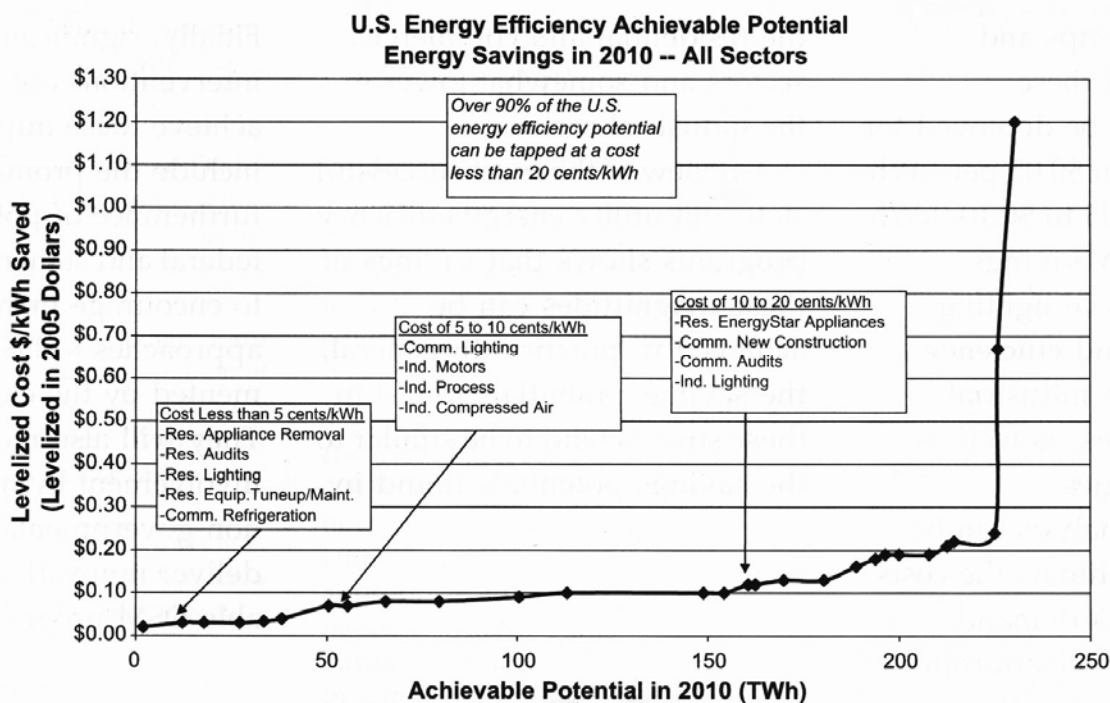


Figure 43. Supply curve for national electric energy savings in 2010 from Gellings et al.⁷⁰

The Commonwealth should emulate best-practice lowest-cost demand side programs from other states, concentrating on peak load reduction to reduce the number of hours when high cost peakers run. To keep costs below those of generation, mandated programs with other social goals should be avoided.

Direct state payments to companies that reduce demand, especially peak demand, can be a cost effective incentive and could expand current Pennsylvania Energy Development Authority (PEDA) programs. Coordinated action between Commonwealth agencies, the Pennsylvania P.U.C. and PJM can make these programs effective.

We have used the model we developed to analyze the effect of real time pricing (section 4.1.4 above) to estimate the effects of a 5% reduction of overall demand in Pennsylvania.⁷¹ This action reduces prices in PJM as a whole by \$8 billion annually. Total annual savings for the Commonwealth are estimated to be \$1.9 billion per year. Commercial customers would see a 1.4 cent per kWh reduction in their rates, and industrial customers 0.9 cents per kWh. The savings are a function of the percent of demand reduction achieved for all loads considered together, as shown in figure 44.

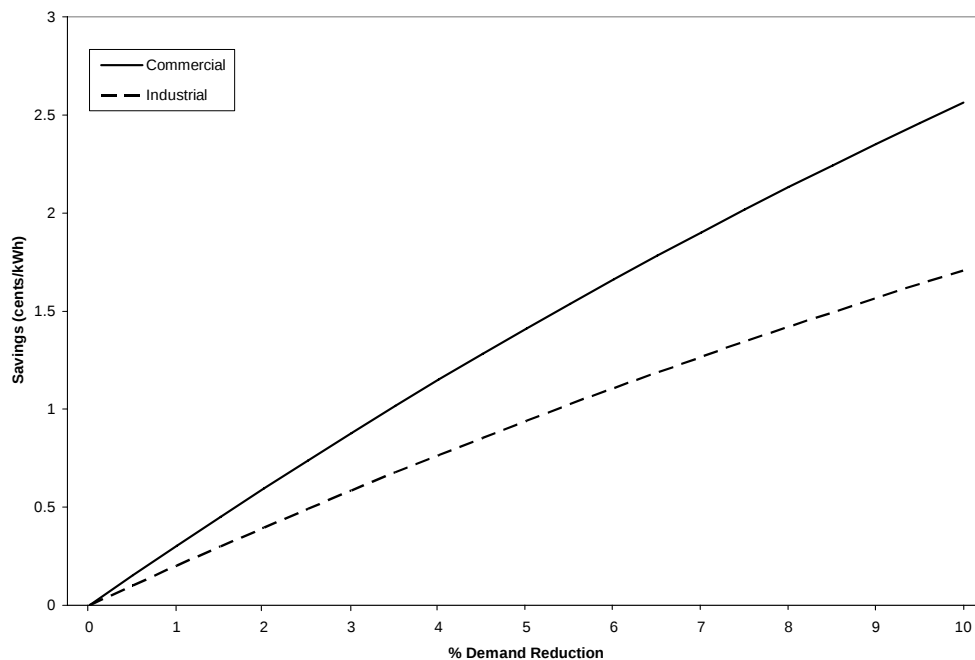


Figure 44. Rate savings for commercial and industrial customers as a function of percent of achieved demand reduction for the total load.

We have used the data in figure 43 above to estimate the cost of implementing a demand reduction program in Pennsylvania. We find that a 5% reduction in demand can be achieved at a blended cost of between 5.5 and 11.2 cents per kWh. This is less expensive than the cost of electricity from either currently operating or new peaking plants. The expenses would be borne by both the Commonwealth through education and grant programs and by consumers.

Since demand in Pennsylvania is currently growing at 2 terawatt-hours per year, we estimate that a 5% demand reduction from current levels could be achieved in 4 years.

The savings from demand reduction and real time pricing are not additive. We find that when both programs are implemented simultaneously the price savings are approximately 0.1 cent per kWh above those of the demand response program alone.

The figures suggest that policies to promote demand reduction (through conservation or energy efficiency) may be more effective at mitigating high electricity prices than real time pricing (which simply acts to shift consumption from peak to off-peak hours). Implementing both may still be desirable because it may be less expensive to put in the meters required for real time pricing for targeted customers than to build new peak generation which would still be required in the case of demand reduction alone. We note that both peak shifting (from real time pricing) and demand reduction have provided numerous entrepreneurial opportunities in states that have implemented these programs, and we would expect the same to be true in Pennsylvania.

4.1.7 Incentives for new generation

The current auction structure in PJM and other RTOs does not provide the correct incentives for building new peak generation, since the uniform-price auction structure implies that the generator on the margin recovers only variable costs and not average costs. Price caps and aggressive market monitoring on the part of PJM have helped to reduce market prices during peak times, but peaking generation, which runs only for a small number of hours each year, relies on high prices during these hours to recover capital costs. The capacity market operated by PJM (meant to make up for this revenue shortfall) has, thus far, not produced the desired investments.

A return to the regulated system which prevailed in the Commonwealth until 1998 would founder on the issue of valuation of generation assets that were sold by formerly regulated vertically integrated utilities. The market value of some coal and nuclear plants has increased dramatically from their depreciated book value under regulation. Others, generally natural gas plants, are less valuable. In addition, there have been beneficial effects of restructuring, including upgrades to the steam generation at nuclear facilities and the pricing offered to certain commercial and industrial customers located near low cost generation which does not have the transmission to sell into high price markets.

If the generation assets that appreciated in price were put into the rate base at their current market value while the generation assets that depreciated in price were put into the rate base at their former book value, the rate of return on these assets would send electricity prices skyrocketing. Attempting to pull in all the assets at their former book value would create litigation that the regulators would probably lose, since they would not be paying fair market value.

A major change in the RTO auction that would ensure competition and lower prices is presented below in section 4.1.8. A more modest change is presented here to get new generation capacity that would lower price. If PJM were slow to implement the change or if Pennsylvania desires a more direct subsidy of industrial rates, that could be accomplished within this option.

The failure of the current restructured market to attract new capacity has led to considerable increases in the hourly market clearing price. Some old, inefficient generators have generation costs exceeding 20 cents per kilowatt-hour. If these plants are needed to satisfy load, the market clearing price will be 20 cents and all generators will be paid this amount. If new capacity were built and these old plants retired, we estimate that market clearing prices would be capped at about 15 cents with considerable saving in most hours.

The PJM capacity market has not provided incentives to build new capacity. Pennsylvania and the other states in PJM could provide that incentive by a variety of means, such as

- negotiated rates to buy electricity over the entire life of the plant,
- loan guarantees,
- tax-free bonds covering most of the capital costs, or
- subsidizing the cost of building the plant.

Each of these incentives would provide an incentive to build the new plant and lower its cost of capital, thus lowering its unit costs. They differ in terms of the cost to the Commonwealth of getting a unit reduction in the cost of generating electricity from a plant. For example, a loan guarantee, tax free bond, or life of the plant contract to purchase electricity would involve no direct state outlays, in contrast to a plant subsidy. However, since the Commonwealth has limited borrowing power, all these options would reduce the Commonwealth's ability to borrow in the future or raise the interest rate of future loans. We have not analyzed the options to see which would achieve a unit reduction in the cost of a new plant at the lowest cost to Pennsylvania.

The output of a new baseload plant built under one of these options could be sold to a group of customers, such as commercial and industrial customers at its unit cost or it could be sold into the PJM market. The lower capital cost of the plant would mean that its unit costs would be attractive for the favored customers. Building the plant would benefit all PJM customers, since it would have the effect of lowering demand. The lower demand would lead to lower prices for all customers (see sections 4.1.4 – 4.1.6 on the effect of lowering demand). Alternatively, the output of the new plant could be bid into PJM. With its favorable cost structure, the plant would be expected to receive revenues over a year that exceeded its costs. If the state has a contract to buy the plant's output at a fixed price, a market clearing price in excess of the fixed price could go to the Commonwealth treasury or used to subsidize electricity to favored customers.

The output of a new peaking plant should be bid into PJM. Building enough new plants would effectively put a cap on the market clearing price of the generation cost of the new plants. We estimate this market clearing price would be capped at 15 cents per kilowatt-hour lowering total customer payments about \$4 billion. However, these plants would never be paid more than their generating costs, not being able to recoup their fixed costs. Pennsylvania and other states would have to pay for the fixed costs of these plants. While building these peaking plants would help electricity customers and economic development, the market would not pay their fixed costs. Options for covering the fixed costs include a "wires" charge, a tax on electricity, or the Commonwealth treasury; this is similar to the Connecticut subsidy of \$500 per kilowatt for new peaking plants.

A Pennsylvania Power Authority could be established to manage the subsidy, handle the bidding process, allocate the output of the new baseload plants, and manage the process generally.

Since Pennsylvania is only a part of PJM, it would maximize the benefit to get agreements from the other states for them to bear their share of the subsidy to new generation. There is little point in having Pennsylvania subsidize the other states in PJM, although unilateral action would still be cost effective.

The lower finance rate for tax free industrial development bonds could lower generating costs significantly. We have analyzed the effects of building new peak generation under such a program,⁷² finding that costs of new peak generation under such a program produces peak power at a cost of 15.6 cents per kWh. This effectively places a cap on the PJM market price, if the generation were required to bid into the PJM market at cost. Total savings in Pennsylvania would likely be approximately 0.7 cents per kWh. Total savings would be approximately \$860 million annually. Allocating Pennsylvania's savings to commercial and industrial customers based on load yields total annual savings of \$250 million for commercial customers and \$260 million for industrial customers. Annual energy cost savings would be 0.6 cents per kWh for each of the commercial and industrial rate classes.

Under reasonable assumptions⁷³ we calculate that the probable wholesale price for baseload Pennsylvania coal generation under such a program would be 6.2 cents per kWh. Thus, the program should be directed to peaking generators, although some customers may value baseload price stability.

The initial goal of such a program should be to replace the very inefficient peaking generators now operating in Pennsylvania. These plants burn a great deal more fuel per kWh of electricity generated than do comparable plants, driving up the price in hours when their power is required. Excluding biomass, co-generation, and waste coal plants, the Commonwealth has 1900 MW of generators with efficiencies between 14% and 22% (heat rates of 25,000 to 15,000 BTU per kWh).⁷⁴ In contrast, the best natural gas plant in Pennsylvania has an efficiency of 52% and the best large coal plant 38% (heat rates of 6,500 and 9,000 respectively). Of these old and inefficient plants with heat rates above 15,000 BTU per kWh, 14 are oil, 1 natural gas, and 2 dual fired with oil or natural gas. They and similar plants in other PJM states are the most expensive points in figure 39. An investment of \$1 billion to replace these 1900 MW of plants would have a payback period of less than two years to consumers.

Connecticut has begun a program similar to this for peak generation (see section 2.3.4 of this report). The Commonwealth should analyze whether such a program has the potential to lower its own bond rating, since Pennsylvania may in the case of a default be liable for the debt. If this is not a significant concern, the savings from this program appear to provide a strong motivation for its implementation.

4.1.8 Changes to the market auction model

Although only 15% of the power sold in PJM is transacted in the hourly and day-ahead PJM markets, the prices in these markets strongly influence the prices for bilateral contracts that make up the other 85%.

As discussed in section 1.2 above (see figure 10), a uniform price or pay as bid auction model over-compensates baseload and shoulder generation during hours when peak generation is needed, while not compensating peak generation sufficiently to cover capital costs.

A different auction model is feasible. This new auction model preserves competition, eliminates the over payments to baseload generators under the current auction, provides incentives for new construction of peaking plants, and will give generation companies profits comparable to those under the regulated system.

The ISO would invite generators to bid on a series of one-year contracts that would give the ISO (as the central dispatcher of generation) the option to call on specific generators when necessary, and would also have a specified number of start-up and shut-down times. Generators located along different portions of the system cost curve (as in figure 39) would likely be offered different contracts. As an example, low-cost baseload generators would be asked to run nearly all the time, shutting down perhaps a few times a year for maintenance. Shoulder plants would run largely during the day, and would be asked to shut down perhaps once per day (some of these plants might run twenty-four hours during peak demand periods). Peaking plants would require rapid start-up and shut-down times, and could be cycled in excess of 700 times per year. Each bidder would agree to have the plant available to generate the specified amount of power on fixed notice, unless they had received permission to take the plant off line for maintenance. A reliability level would be specified in the contract. Plants that met this reliability level and other terms of the contract would be paid their fixed costs and their variable costs for the number of MWh they were asked to generate. Since each unit would be paid its contract price, no unit would be over- or under-compensated.

We anticipate the generators would be reluctant to participate in this auction. If they did, they would bid prices above their actual fixed and variable costs. In bidding into an hourly market, if a generator submits too high a bid and is not selected, they lose their profit for that hour. Since there are 8759 more hours in the year, there is little reason to regret the high bid. Computer simulations⁷⁵ and experiments show that bidders were able to achieve market clearing prices higher than cost after 40 -

100 hourly auctions. The advantage of having an annual auction is that a generator bidding too high would lose a year of profit, a much higher penalty.

If, despite the penalty of not supplying power for a year, the ISO found that some generators were still bidding too high, lengthening the contract would put even more pressure on the generator to be competitive. However, a large generator might have market power during many hours of the year. In that case, the generation might bid at a high price, knowing that the ISO would have to buy the power for at least some hours.

If this occurred, the ISO would offer some “life of the plant” contracts. Adding new capacity to the market would mean that the existing capacity would be used less, lowering their profits. Thus, current generators would not want to see new capacity added. If there were sufficient new generation plant sites available, we expect that there would be a competitive market for new generation. A life of the plant contract with a credit-worthy entity would enable the winner to finance the new plant at favorable rates.

We have two qualifications to this proposal. The first is the likely bid price. Ultimately, the discipline on bidders is a new plant. Since the capital costs of new plants are greater than those of previous plants, the cost of power from the new plant is likely to be greater than the cost from existing plants. Thus, owners of existing plants would see that they could bid fixed and variable costs up to the level of a new plant and still have the ISO accept their bid. Thus, this system would place a cap on bids equal to the cost of a new plant, rather than the actual fixed and variable costs of existing plants.

The second qualification is that it takes time to construct a new plant. Assume that it took 7 years to construct a new baseload plant. If so, the ISO would have no discipline on bids for the next seven years. The owners could use their pivotal status to demand high prices. However, when the new plant came online, it would be committed to run continuously, thereby reducing the demand for the existing plants. The threat of this new capacity would give the ISO some power in holding down current bids. This second qualification is less important since the threat of mitigation by current RTO market monitors induces many generators to bid their plants at close to marginal cost.

This proposal preserves competition in the long-term sense of competition for new plants. It eliminates hourly markets and thus lowers the ability to implicitly collude. The ISO would have to decide what fuels and technologies to choose for new generation, as well as its location. These decisions have been made, not always well, by electricity companies since Edison’s Pearl Street Station. We don’t minimize the difficulties of making good decisions, but emphasize that there is nothing new here. In this proposal, the ISO would have to do the economic dispatch, something that was managed by utilities in the past. Whether this system would be superior to the current one depends on the following:

- What is the cost of new capacity? If capital costs are high, a new plant might be more expensive than current bids.
- There must be a number of attractive sites for new plants that do not engender public opposition. The sites have to be attractive in the sense of inexpensive land, easy access to cheap fuel, and easy access to transmission with sufficient capacity to carry the power.

A simpler alternative would be for the ISO or the state to build new power plants and have them bid into the system at their fixed and variable cost. If the state were willing to finance the plant with tax free industrial development bonds, the capital cost of the new plant could be reduced greatly, making the auction much more competitive. We have addressed this option in section 4.1.7 above.

These contracts would be subject to some difficulties. A multi-year contract might not be able to hedge on fuel prices for the entire period. If so, to the possibility of future fuel price changes would need to be considered. The entire risks could be put on the provider, on the ISO, or they could be shared. We

suspect that the plant owner would be more risk averse than the ISO and so putting the entire risk on the owner would raise costs. The current method of putting the entire risk on the rate payer removes any incentive for the owner to search for lower priced fuel. We suggest some sort of risk sharing, as is done in regulated states that have shifted from traditional rate-of-return regulation to performance-based regulation.

A multi-year contract has a risk of more stringent environmental standards during the lifetime of the plant. Again, we suggest some sort of risk sharing rather than putting the entire burden on the rate payer.

The contracts would pay the owner only if the plant provided the power called for in the contract. The owner might not be willing to do this if he could sell the power elsewhere for a higher price, if the plant became unprofitable to operate, or if he were not able to operate the plant efficiently and reliably. The first difficulty could be covered by a performance bond that would be provided by various firms. The second difficulty could be handled by setting the fuel and environmental risk sharing so that it was more profitable to operate than to shut down. If something unexpected happened that violated this condition, the ISO would have to renegotiate the contract. The final difficulty is common to all new capital structures that are built: The owner is responsible for being able to operate the plant efficiently and reliably. Since there is nothing unique to an electricity generating plant here, we believe that investors would not be put off by this risk.

We have modeled the effect of the proposed new auction model on prices.⁷⁶ Total annual savings to PJM would be \$3.7 billion, with Pennsylvania's share \$800 million. Annual energy savings for the commercial and industrial classes would be 0.6 cents per kWh and 0.4 cents per kWh, respectively.

4.2 Options for commercial and industrial customers to bypass LMP-based rates

4.2.1 Encourage co-generation and self-generation

Companies in Pennsylvania own and operate 1300 MW of their own electric generation capacity. Some of this is used for combined heat and power (called co-generation), while some is electricity-only generation (self-generation).

Companies we interviewed for this study that have such capacity use it very effectively to lower their expenditures for power. They run their co-generation or self-generation at full capacity when prices are high in PJM, and run at idle when grid prices are lower than their generation costs.

Such generators lower the cost of peak power for everyone, since fewer high cost units must be dispatched to meet demand.

When generation by such facilities exceeds the company's needs, the company is allowed to sell back to the grid. However, current rules generally set the payments for such sell-backs at 2-3 cents per kWh below nearby locational marginal prices. The differential between the hourly LMP and the sell-back price should be reduced significantly or eliminated through coordinated actions by the Pennsylvania P.U.C. and PJM.

A natural gas self generation plant could produce electricity for 6.5 cents per kWh.⁷⁷ These gas-fired plants can be economical for a commercial customer-generator to operate because they are used as baseload plants, with costs well below the average of 8.9 cents per kWh commercial customers pay in the state.

Industrial customers in high-price areas of the state may find these plants lower their power cost, but the cost advantage is small and the payback time long.

Connecticut has begun a program that provides a one-time state payment of \$500 per kW of new co-generation or self-generation.⁷⁸ Since many companies have a 20% hurdle rate and a 5-year planning horizon, and investments must pay out in 2 ½ - 3 years, such incentives can be effective in stimulating investments by customer generators. The program could be socially beneficial in both providing low cost process heat and power for the company and in lowering peak electricity prices for all.

With a program similar to Connecticut's a self-generation plant could be brought on line to deliver electric power at approximately 5.6 cents per kWh, below the average industrial price of 6.4 cents per kWh.

If self-generation and co-generation is encouraged it can have a significant effect on prices for all customers. As the discussion in section 4.1.5 above indicated, a 5% demand reduction would lower prices in the Commonwealth for commercial and industrial customers by approximately 0.5 cents per kWh. Installing new facilities equal to double the current installed base of co-generation and self-generation would effectively reduce demand by 5%. If a Connecticut-like subsidy were used, the total cost of such a program would be \$1.4 billion, somewhat larger than the cost of a demand reduction program of comparable size.

Targeted self-generation programs for customers who can efficiently use the generation to lower their costs appear justified.

4.2.2 Aggregate potential users of co-generation and self-generation

The Commonwealth may be able to offer other services that can lower customer costs through co-generation and self-generation. First, some natural synergies already exist in malls and similar facilities with significant demands for electricity as well as heat. The impediment to establishing a co-generation facility is the exclusive right given to a LSE to supply electricity in the area. Since there is more than one customer for the electricity, establishing a microgrid infringes on the right of the LSE. Commonwealth laws should be changed to allow the development of microgrids.⁷⁹ Second, using the new data base developed as part of the IBM Team Pennsylvania Foundation study, the Commonwealth can identify customers whose time of use patterns and locations make a local co-generation facility attractive. For example, a company burning natural gas for low temperature process heat is an ideal partner for a company requiring electricity but little steam. Third, PEDAs should study the benefits and costs of providing low cost financing to co-generation or self-generation projects, either for a single consumer or for an aggregated group.

4.2.3 Take advantage of special situations for commercial and industrial customers

Pennsylvania has a number of special infrastructure opportunities, such as U.S. Steel's Mon Valley transmission and gas lines that provide a favorable location for generation facilities. In return for providing low cost power (for example, 80 MW required by the firm), the power plant would receive good transmission, a cleared site, and access to rail and barge shipments. The remaining output (500 – 900 MW) would be sold at cost plus rate of return to commercial and industrial customers in long-term bilateral contracts.

4.3 Provider of last resort (POLR) requirements

4.3.1 Risk premium

POLR rates include a risk premium due to the ability of customers to switch suppliers with little notice, and to return with little notice. These providers face higher costs because they cannot make long-term commitments to suppliers. Similarly, competitive suppliers build in risk premiums (estimated by most suppliers we interviewed to be 2 – 5%; one estimated 10%) for the same reason. Since those who

switch impose a cost of those who will not switch, it seems fair to either charge those who switch a premium or to require all customers to commit for a period such as one year.

Most suppliers believe that the risk premium would be reduced if customers were required to give a minimum notice for switching that is much longer than the period current rules permit. An alternative is to price POLR and competitive supply like cellular phones – a contract term with a fee or penalty for early termination.

The mid-range of the risk penalty estimates would lead to average rate reductions of 0.3 cents per kWh for commercial and 0.2 cents per kWh for industrial customers, if the LSE is required to pass the savings on to customers.

4.3.2 POLR auction timing

Some jurisdictions require that the provider of last resort hold an auction on a date certain to purchase power it needs to supply its customers. A number of our interviews indicated that flexibility in the timing of purchases of blocks of power is critical in lowering costs. The New Jersey auction model takes steps in that direction, but the POLR provider should be able to exercise wide latitude in the timing and size of auctions. Requirements such as the one in Penn Power which mandated an 18 month contract for all load in a single auction on a certain date tend to drive up the price paid, and such requirements should be eliminated.

4.4 Change the climate for long-term electric power contracts

Long-term contracts are unlikely to lower prices unless they are signed during periods of low spot market prices, since long-term contracts reflect recent spot prices plus a risk premium. We doubt that utility hedging would be profitable. However, introducing long-term contracts in areas where they are currently prohibited may provide the certainty required for construction of new generation, the flexibility to lock in prices at a time of the customer's choice, and price stability for customers who value low volatility.

4.4.1 Allow POLR providers to sign long-term sales contracts

Both the Pennsylvania P.U.C. and the courts have in recent years denied permission for POLR providers in both the east and west portions of Pennsylvania to offer long-term contracts to industrial and commercial customers. Permitting POLR providers to sign long-term sales contracts may allow rate reductions, due to the high creditworthiness of POLR providers and consequent lower risk premiums. This will be seen by power marketers as favoring POLR providers, but this advantage may simply offset the requirement to accept any customer (the last resort) and the requirement to provide ancillary services. We note that if a POLR provider is not able to offset the long-term sales contract with a long-term generation contract, the POLR provider could be at significant financial risk if its price for purchased power rises. As in any contract, if the POLR provider signs contracts at the peak of fuel or market prices, backed by long-term generation contracts (as was the case in Pike County), it may be criticized, particularly if prices subsequently fall. Long-term POLR contracts can also provide incentives for new generation.

4.4.2 Encourage PJM to offer forward markets for ancillary services

In the Western states, it is possible to sign full requirements contracts (energy plus the associated services such as voltage regulation) for terms up to ten years. However, in PJM the ancillary service markets do not extend beyond three years. While the prices and volumes in such markets may make long-term contracts unattractive, these forward markets would at least provide the possibility of long-term full requirements contracts.

4.4.3 Speed up the approval process for long-term contracts

Commercial and industrial customers interviewed for this study stated that requests for long-term contracts had been pending before the Pennsylvania Public Utility Commission for long periods. The ability of companies to execute bilateral contracts at terms and times mutually agreed between buyer and seller is fundamental to markets, and should not be delayed by government.

4.5 Coal gasification strategies for energy

While the focus of the scope of work is directed to electricity options, many of the industrial and commercial consumers we interviewed are spending a larger fraction of their energy budget on natural gas than on electricity.

Natural gas supply in North America is declining, and will do so even if the proposed pipeline from Alaska is constructed. Demand has increased in recent years, driven by the unprecedented pace of building natural gas electric power generators. The inevitable result has been that the price of natural gas has been bid up.

The abundant coal in Pennsylvania and similar states can be used in coal gasification with methanation plants to produce synthetic natural gas (SNG). The U.S. Energy Information Administration projects that by 2020, 20% of pipeline supplies will be imported LNG (largely from the Middle East and other unstable regions). As an alternative source of supply, SNG could be produced in Pennsylvania from local coal at lower cost than pipeline gas.

The Governor of Indiana recently announced⁸⁰ a major coal to SNG project that would produce 15% of Indiana's gas supplies over 30 years at 20% lower cost than the average gas utility purchases over the past three years and over long-term EIA projections of pipeline deliveries. The SNG price will be \$6.10 per million BTU, compared to the average cost of natural gas delivered to Indiana over the past 3 years of \$7.82. A \$2.00 savings (in 2006 dollars) for 40 billion cubic feet of production saves Indiana ratepayers \$80 million annually, in 2006 dollars. (The average price of natural gas delivered in Pennsylvania was \$8.98 over the same period). The reduced SNG costs in the Indiana project are attributed directly to capital cost savings from the 30 year federally guaranteed debt backed by 30 year purchase agreements approved by the Indiana P.U.C.. The project is also said to produce 600 mining and operating jobs annually, 1000 construction jobs for 3 years, and adds to the tax base.

This facility will be used to produce SNG in the winter, when gas demand is high. In the summer, some of the output will be used to produce electricity when demand for electricity is high.

Major coal to SNG or integrated gasification combined cycle (IGCC) electricity plants require investments of \$1-2 billion in capital cost to design and construct. To arrange either conventional financing or qualify for the federal loan guarantee program (a part of the Energy Policy Act of 2005), it will be necessary to establish creditworthiness by securing long-term purchase agreements with gas or electric utilities for the project's gas and electric output. To make these contracts creditworthy the contract must be approved by the P.U.C. with provisions for binding cost recovery from ratepayers during the term of the contract. Prior to approval, the P.U.C. must determine that the long-term contracts are reasonably priced and are prudent price hedges in the volatile natural gas commodity market. The federal loan guarantee program is authorized to offer very favorable terms and low interest rates that, in the case of an SNG project, reduce ratepayer cost by one third compared to conventional financing. Without knowing that a long-term purchase contract from utilities would be available if the P.U.C. found it's terms to be prudent, it is unlikely that any developer would invest the \$20-50 million for initial design studies for the project because it would be unlikely that the project could attract financing.

Two members of the Carnegie Mellon Electricity Industry Center studied the project, estimating that SNG prices from the project are likely to save Indiana ratepayers over \$3 billion over the life of the

project compared to purchasing gas supply from interstate pipelines.⁸¹ Based on a probabilistic distribution of energy prices, there is a 98% probability that the Indiana SNG price will be below the average market price over 30 years. In addition to lower prices, long-term contracts provide a physical hedge that protects against price volatility of the commodity. Reduction in that volatility was estimated to provide another \$1.8 billion in value to customers.

Coal gasification for production of electric power is also feasible. The hydrogen and carbon monoxide produced by the gasifier is burned in a combustion turbine (usually an efficient, combined-cycle unit). There are currently eight such facilities operating worldwide producing about 1.7 GW of electricity from a coal or petcoke feedstock.⁸² Two members of the Carnegie Mellon Electricity Industry Center have analyzed the profit potential of these units, with current construction costs. These facilities used as baseload generators presently have slightly less profitability than the SNG production facilities. However, our analysis shows that profitability is markedly improved when the facility is run 24 hours a day (as the gasifier is designed to do), but stores the output gas when demand for electricity is low. By using the stored gas in parallel with the output gas when demand and prices are higher (during the day), the return on investment becomes profitable.

As in the case of the Indiana facility, such coal gasification plants benefit from long-term offtake contracts.

4.6 Transmission

4.6.1 Transmission planning

There is currently no transmission planning entity that has as its goal price reduction for Pennsylvania consumers. Building more transmission lines within Pennsylvania would bring eastern and western prices closer together. New lines from Pennsylvania generators to high price areas (New Jersey, New York, and Maryland for example) are likely to increase prices for Pennsylvania customers. In contrast, new lines to West Virginia and Kentucky would be likely to lower prices to Pennsylvania customers.

One policy suggestion from our interviews was that Pennsylvania should undertake its own transmission planning, separate from PJM. To comply with FERC rules (which give PJM and MISO primary responsibility for transmission planning within their respective footprints), this would require Pennsylvania to establish a state Power Authority that would need to file tariffs with FERC. Even then, Pennsylvania's transmission planning organization would supplement, rather than replace, transmission planning in PJM.

An alternative is to establish a strong state transmission coordinating body with membership from the Department of Community and Economic Development and the P.U.C. that would ensure the Commonwealth's interests were well defined and well represented in RTO transmission planning.

4.6.2 Transmission rights

Some POLR providers hold valuable transmission rights. The Pennsylvania Public Utility Commission might require that these are allocated to certain loads. These rights are worth approximately \$300 million annually. This might lead to a 3 to 5% rate decrease for the favored loads (0.3 – 0.4 cents per kWh for targeted industrial and commercial customers). Thus, these rights act as a subsidy by giving a no cost hedge to these loads.

4.7 Optimize the Advanced Energy Portfolio Standard after 2015

At the time that rate caps expire in the majority of Pennsylvania, the AEPS will not change electricity costs significantly, and the AEPS helps by providing incentives for new generation. The subsidy for plants burning waste coal will probably lower electricity prices slightly while the mandate

for 800 megawatts (MW) of solar photovoltaic power will raise prices after 2015 above what the price would be if the power were supplied by another renewable source, wind energy, unless solar costs fall significantly compared to wind.

The Commonwealth should continue to monitor the costs of solar PV as the large-scale implementation deadline approaches.

Wind and solar photovoltaic power are both intermittent resources. Wind turbines in the state generate power approximately a quarter of the time they are operational, and the power falls and rises rapidly. Solar photovoltaic power in Pennsylvania generates electricity about 15% of the time with rapid variations in generation. This intermittency can be handled very well by the grid operators, but there is a cost associated with the required voltage regulation and other ancillary services. The Pennsylvania Public Utilities Commission or the Department of Environmental Protection should undertake periodic reviews to ensure that the actual costs of regulation and other ancillary services are not significantly adding to the wholesale cost of power due to intermittency of Tier I AEPS sources.

Some provisions of the AEPS, such as electric generation from trash and farm waste, can be economical sources of power but are not implemented by commercial and industrial customer generators because of internal company requirements for quick return on investment. Pennsylvania Energy Development Authority funding mechanisms may be effective and economical in encouraging such investments, and should be studied.

All alternative energy programs in the Commonwealth, and all environmental regulations significantly affecting the electric power sector should be required as part of the benefit/cost analysis of new requirements to calculate the effects on the price of electricity.

4.8 Tax options

4.8.1 Tax option metrics

Nearly all governments desire to attract companies that will create new jobs. Many compete with other jurisdictions by offering subsidies such as low cost power, free land, a moratorium on taxes, working training, and payments for infrastructure such as utilities and roads. States such as Kentucky offer subsidies to utilities (for example, in the form of credits for coal mining jobs resulting from power production). Subsidies can be effective in regulated states, but are less likely to lower prices in restructured states when non-subsidized generation is the unit setting the market-clearing price.

Some states offer tax credits or other subsidies to industry to lower their effective cost of power. These may include relief from property or corporate income taxes.

The fiscal reasons for not giving a subsidy include opening the door to demands from other plants for subsidies, the chilling effects on employers and residents of having to pay higher taxes or electricity rates to fund the subsidy, and the administrative costs of a transfer program, such as having to verify that each company is in compliance with the agreement.

Transfer payments, whether made from general tax revenue or from other ratepayers should follow several guidelines. First, the mechanism for subsidies should have low administration costs, and the mechanism should not cause undesirable investments. Second, the transfer payments should be focused on achieving the goal of getting employers to stay or locate in Pennsylvania at lowest cost, which generally does not require achieving direct price parity with other states. Third, the metrics for such transfers (total annual cost, annual cost per job, annual cost per job including multipliers for indirect jobs) should be evaluated in comparison with similar programs.

For example, Bartik has examined the costs of tax incentive programs to attract industry. His annual total cost estimates ranged from \$3,000 to \$17,000 per job in 2006 dollars.⁸³ A study of 374 tax abatement agreements in Texas estimated annual total costs of \$15,000 per job in 2006 dollars.⁸⁴

The goal of these programs is to increase jobs in Pennsylvania. Thus, the metric for evaluating each proposed subsidy should be tax dollars per job created or retained, direct and indirect.

Several of the electric suppliers we interviewed told us that industrial development policy should be kept separate from electric rate policy. However, several authors note that reductions of expenditures on energy and other utilities are generally considered by industry to be more important than direct tax incentives.⁸⁵

A number of those interviewed for this study felt that any economic development policy implemented through rates should be open and visible. Some also felt that it would be undesirable to have an economic development tariff administered through POLR providers, since it would inhibit competition. One example that was felt to be both open and neutral with respect to suppliers is a reduction in current electricity taxes, such as the gross receipts tax.

4.8.2 Pennsylvania gross receipts tax

The current Pennsylvania gross receipts tax rate on sales of electric power to customers within the Commonwealth is 5.9%, last amended in 2002.⁸⁶ Total sales of electric power within the state in 2005 were \$12.4 billion, so we estimate the total revenue from the in-state portion of this tax is approximately \$730 million. The tax is paid by generators. One of those interviewed for this study noted that the gross receipts tax on natural gas was eliminated during natural gas deregulation.

If the perceptions by customers and suppliers are correct that electricity prices will increase when rate caps are removed in the majority of the state, the Commonwealth will receive increased revenue from the tax, a portion of which might be used to offset price increases.

The gross receipts tax might be removed for economic development classes. If 20% of electric power in the Commonwealth were sold under economic development rate tax abatement, the foregone tax revenue would be approximately \$145 million. The cost of power for commercial customers under such a plan would be reduced by 0.5 cents per kWh, and for industrial customers 0.4 cents per kWh, if the generators were required to pass the tax savings on to customers.

4.8.3 Cross subsidies

A number of states have one rate class subsidize another. In Pennsylvania, the ratio of average prices among the three rate classes are very similar to the ratio of prices in Ohio, West Virginia, and Kentucky. New York appears to favor industrial rate payers, while New Jersey appears to disadvantage both industrial and commercial rate payers (although their rates are lower than those of residential customers, they are not nearly as low as in other states).

It is commonly believed that in restructured states, industrial customers now pay a larger share of the electric power bill than they did under regulation. That is not the case in Pennsylvania, where the ratio of industrial to residential prices is identical to that before restructuring (figure 45). The ratio in Pennsylvania is very similar to that in Kentucky and West Virginia.

However, in the Duquesne Light territory, industrial customers are indeed paying a larger share of the total bill after rate caps were lifted than before restructuring. We note that DQE industrial customers were paying the smallest fraction of any territory in the Commonwealth before restructuring. Industrial customers in Duquesne's territory are now paying the fraction common in the rest of Pennsylvania (figure 46).

It is our judgment that a debate over cross subsidies is a distraction from more productive policy avenues. In the restructured environment, cross subsidies are open and visible. If residential or commercial customers were asked to subsidize industrial customers, there would be intense protest.

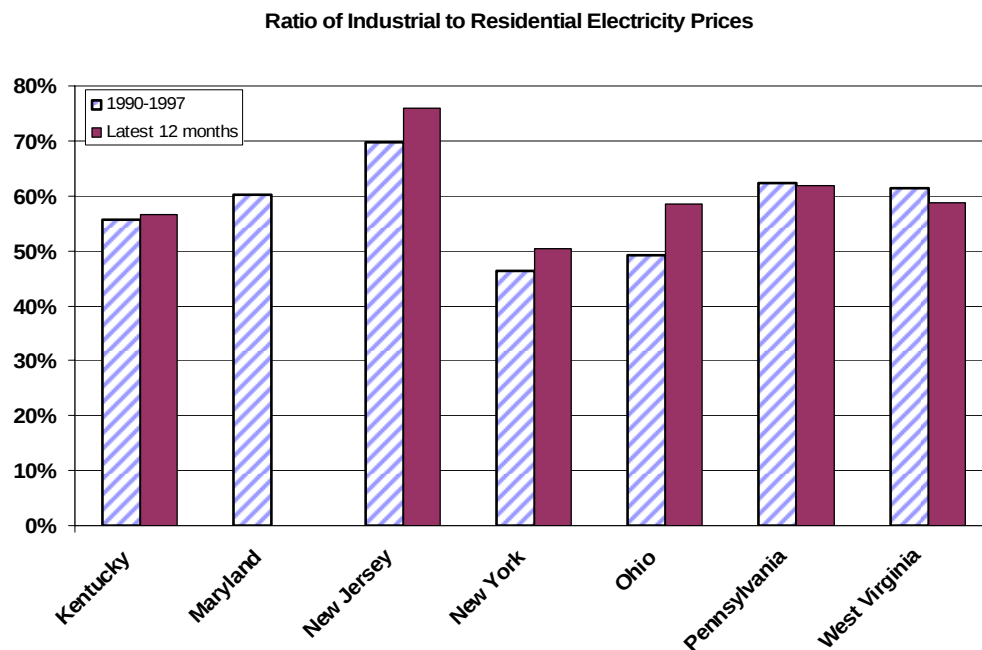


Figure 45. Ratio of industrial to residential prices before restructuring (cross hatched bar) and for the 12 months ending in September 2006 (solid bar). Data for Maryland industrial customers are unreliable for 2006 and are not shown.

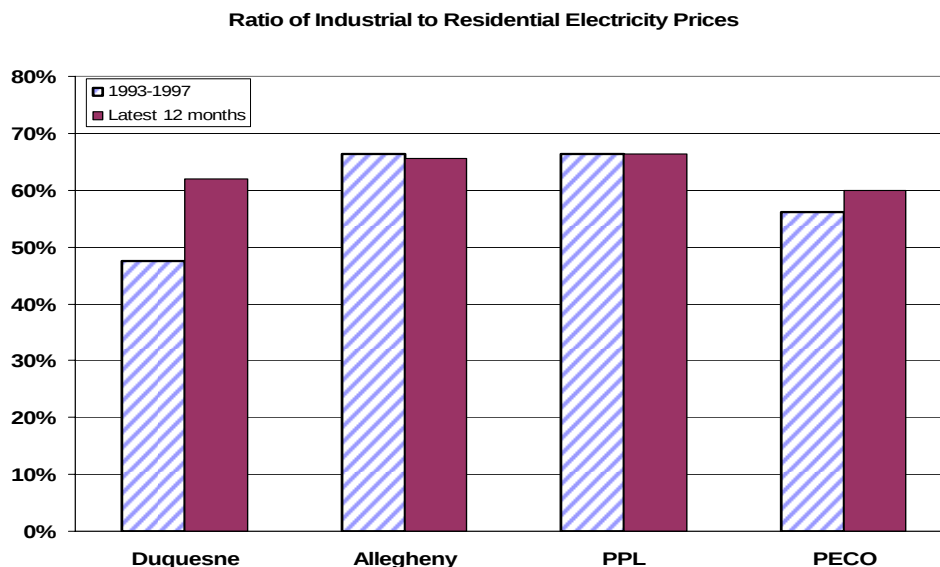


Figure 46. Ratio of industrial to residential prices before restructuring (cross hatched bar) and for the most recent 12 months (solid bar) for selected Pennsylvania load serving entities. Data source: EIA form 826.

References and Notes

- ¹ Data for calendar year 2005 from the U.S. Energy Information Administration Electric Power Monthly. Texas and Florida were the first and second largest producers.
- ² Unless otherwise indicated, monthly electricity sales and revenue data in this report are from the U.S. Department of Energy, Energy Information Administration, Current and Historical Monthly Retail Sales, Revenues, and Average Retail Price by Sector data available at http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls
- ³ *PJM Load Forecast Report January 2007*, available at <http://www.pjm.com/planning/res-adequacy/downloads/2007-load-report.pdf>, shows PJM-wide growth to be 2300 MW per year. Pennsylvania represents 147 of the 690 terawatt-hours (TWh) of PJM energy, or 21%. A second way of calculating the projected Pennsylvania growth is to note that the rate of growth of Pennsylvania use has been 2.7 TWh per year since 2000. At a 60% average capacity factor, this energy requires 514 MW of generation.
- ⁴ Source for data prior to 1990, Hirst, R.F., *Power Loss*, (1999) MIT Press, Cambridge.
- ⁵ U.S. Department of Energy, Energy Information Administration, Form EIA-860, as of 12/31/05.
- ⁶ Interview with Andrew L. Ott, Vice President for Markets, The PJM Interconnect, Inc., October 10, 2006.
- ⁷ Rose, K. and K. Meeusen, *2006 Performance Review of Electric Power Markets*, Review conducted for the Virginia State Corporation Commission, August 27, 2006, at p. 15. Available at http://www.scc.virginia.gov/caseinfo/reports/2006_rose_1.pdf.
- ⁸ *Ibid.*, at p. 6.
- ⁹ Hirst, E. and B. Kirby, *Transmission Planning and the Need for New Capacity*, December 2001, see <http://www.ehirst.com/PDF/TXPlanningNTGS.pdf>.
- ¹⁰ Cross, P.S., “Return on Equity”, *Public Utilities Fortnightly*, 144:11 (2006) at 42-46.
- ¹¹ *PJM 2005 State of the Market Report*, at 133-134. Available at <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20060407-som.pdf>.
- ¹² Chirstensen, L.R. and W.H. Greene, “Economies of Scale in U.S. Electric Power Generation”, *Journal of Political Economy*, 84:4 (1976) at 655-676.
- ¹³ Kleit, A.N. and D. Terrell, “Measuring Potential Efficiency Gains from Deregulation of Electricity Generation: A Bayesian Approach”, *The Review of Economics and Statistics*, 83:3 (2001) at 523-530.
- ¹⁴ Niederjohn, M.S., “Regulatory reform and labor outcomes in the U.S. electricity sector”, *Monthly Labor Review*, 26:5 (May, 2003) at 10-19.
- ¹⁵ Douglas, S., “Measuring Gains from Regional Dispatch: Coal-Fired Power Plant Utilization and Market Reforms,” *Energy Journal* 27:1 (2006), at 119 – 139; Bushnell, J., and C. Wolfram, “The Impact of Electricity Generating Plant Divestitures on Operating Performance,” University of California, Berkeley, mimeo, cited in C. Wolfram, “The Efficiency of Electricity Generation in the U.S. After Restructuring,” in *Electricity Deregulation: Choices and Challenges*, J. Griffin and S. Puller, eds., University of Chicago Press, Chicago (2005).
- ¹⁶ Rose, K. and K. Meeusen, *op. cit.*, at p. 68.
- ¹⁷ Klitgaard, T. and R. Reddy, “Lowering Electricity Prices Through Deregulation”, *Current Issues in Economics and Finance*, 16:14 (December 2000) at 1-6, Federal Reserve Bank of New York
- ¹⁸ Pike County Power & Light Company has argued “Given its size, location in the far northeast corner of Pennsylvania, and affiliation with both the System and the NYISO (rather than PJM), Pike is plainly unique among Pennsylvania utilities. In light of these fundamental differences, Pike should not be viewed as a bellwether for the other Pennsylvania utilities on issues regarding default service protocols, procedures and requirements.” Petition of Pike County Light & Power Company for

Exception to Rate Cap Limitations Under 66 Pa.C.S. § 2804(4)(iii)(D) and for Expedited Proceedings Under 66 Pa.C.S. § 2804(4)(iv); Doc. No. P-00011872.

- ¹⁹ U.S. Department of Energy, Energy Information Administration, Electric Power Monthly September 2006, available at http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.
- ²⁰ Kwoka, J., *Restructuring the U.S. Electric Power Sector: A Review of Recent Studies*, report for the American Public Power Association, December 2006 and J. Eto, D. Hale, and B. Lesieutre, “Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies: A Review of Recent Benefit-Cost Studies of RTOs,” *Electricity Journal* 19:10 (2006), at 50 - 62. Kwoka’s paper focuses on the econometric shortcomings of existing studies and concludes that none represent statistical best practices. Eto *et. al.* focus on data and methodological issues. Another discussion of the metrics used to critically evaluate electricity restructuring can be found in Blumsack, S., “Measuring the Costs and Benefits of Regional Electric Grid Integration,” *Energy Law Journal*, forthcoming (2007).
- ²¹ Lave, L.B. and J. Apt, *Electricity Options for Large Industrial Customers in Western Pennsylvania*, report to the Allegheny Conference on Community Development, August 2005. Hereinafter, the “Allegheny Conference” report.
- ²² Since LMPs are typically higher in Eastern Pennsylvania than in Western Pennsylvania, these charges will have a relatively larger or smaller impact in different portions of the Commonwealth.
- ²³ *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service*, Docket No. P-0032071, Order entered August 23, 2004.
- ²⁴ Statement of Commissioner Bill Shane in Docket No. M-00061957.
- ²⁵ Commission Docket No. M-00061597, adopted May 19, 2006.
- ²⁶ *Impacts of the PJM RTO Market Expansion*, Energy Security Analysis, Inc., November 2005.
- ²⁷ Whether the definition of “the market” is limited to the PJM hour-ahead or day-ahead spot market has been the subject of some debate, as discussed *infra*. The relevant language can be found in 66 Pa. 28, § 2807 (e)(3): “...if a customer contracts for electric energy and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or commission-approved alternative supplier shall acquire electric energy at *prevailing market prices* to serve that customer and shall recover fully all reasonable costs.” [emphasis added]
- ²⁸ Commission Docket No. M-00061597, adopted May 19, 2006.
- ²⁹ Initial Order in Docket No. M-00061597, at 4 – 8.
- ³⁰ Comments of Commissioner Bill Shane in Docket No. M-00061597.
- ³¹ The argument is that the increase in generation costs would be offset by the elimination of the stranded cost charge on customer bills.
- ³² Pennsylvania Consolidated Statutes, Ch. 28.
- ³³ See, for example, the comments of David Boonin in Docket No. M-00061597.
- ³⁴ Some states have restrictions on who can shop for generation service and who cannot. Pennsylvania was somewhat pioneering in that it introduced retail competition for all customer classes simultaneously. New York, meanwhile, phased-in full retail competition over a number of years. Oregon, for example, allows retail competition only for its largest customers.
- ³⁵ Analysis of the New Jersey auction results for commercial and industrial customers is not possible since the data has not been made public, although New Jersey’s restructuring law mandates an hourly default service price for commercial and industrial customers. The auction yielded residential default-service rate increases of between 18.6% and 28.3%. See “Post-Auction Report on the New Jersey Utilities’ Basic Generation Service Auction Processes,” in Docket EO05040317, February 2006.
- ³⁶ Rose, K. and K. Meeusen, *op. cit.*, at p. 20.
- ³⁷ *Ibid.*, at p. 24.

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- ³⁸ The Maryland Public Service Commission reports that a systematic analysis of the large commercial and industrial rate classes is not possible due to the heterogeneity of the individual customers and the existence of a market-based pricing option for these customers. See *Report/Observations on the Standard Offer Service Bidding Process and Results* in Case 8908, March 2006.
- ³⁹ *Post-Auction Public Report of the Staff*, Illinois Commerce Commission, December 2006, at. 2 – 3.
- ⁴⁰ *Ibid.*, at p. 17.
- ⁴¹ Rose, K. and K. Meeusen, *op. cit.*, at p. 62.
- ⁴² Joskow, P., “Markets for Power in the United States: An Interim Assessment,” *Energy Journal* 27:1 at p. 8.
- ⁴³ The capacity would receive a fixed payment from the State, but would bid into the capacity market in ISO New England just like any other generating resource.
- ⁴⁴ Unlike in New England, the PJM market currently has a number of large west-to-east transmission projects being pursued by various transmission owners. Depending on the exact location of these projects (if they are successful), the increased ability to move inexpensive coal generation to markets in Eastern Pennsylvania could obviate the need for a Connecticut-style generation procurement. Policymakers in Pennsylvania will need to carefully assess the likelihood of these transmission projects going forward.
- ⁴⁵ Lave L.B., J. Apt, and S. Blumsack, “Rethinking Electricity Deregulation,” *Electricity Journal* 17:8 (2004), pp. 11 – 26. When congestion is present in the transmission network, some generators may earn less than the market-clearing price and it is possible that some may earn more. Some have proposed replacing the uniform-price auction with a structure known as the discriminatory-price or pay-as-bid auction, where each successful generator is paid its bid rather than the bid of the marginal unit. Theory and experimental evidence suggest that generators will adjust their bidding strategies in the pay-as-bid auction to replicate the results of the uniform price auction. A review of the evidence can be found in the California Power Exchange Blue Ribbon Panel Report, “Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?” January 2001.
- ⁴⁶ U.S. Department of Energy, Energy Information Administration, *State Electricity Profiles 2004*, Table 4. Electric Power Industry Capability by Primary Energy Source, 1990 Through 2004, available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept04pa.xls.
- ⁴⁷ Our calculations contrast with figures from PJM that natural gas was on the margin only 26% of the time. Data on the marginal fuel in the PJM market can be found at <http://www.pjm.com/markets/energy-market/real-time.html>. The difference is likely due to different calculation methodologies; we calculate the number of hours that natural gas is given any weight in the hourly marginal-fuel calculation. PJM calculates LMPs every few minutes for their real-time market, but publishes price and marginal fuel data only on an hourly basis. Thus, it is possible for several different fuels to be on the margin during different time intervals within a given hour. PJM’s calculation is based on the number of times that natural gas is on the margin relative to the total number of distinct marginal fuels.
- ⁴⁸ Available at <http://www.epa.gov/cleanenergy/egrid/index.htm>.
- ⁴⁹ The coal generation would need to have a fast ramp rate and short start-up, shut-down, and minimum-run times in order to accommodate shoulder and peaking demand, as gas and oil units do currently.
- ⁵⁰ Hirst, E., *U.S. Transmission Capacity: Present Status and Future Prospects*, Edison Electric Institute and U.S. Department of Energy working paper, 2004, and Joskow, P., *Patterns of Transmission Investment*, working paper, 2005.
- ⁵¹ See Section 3 of the PJM Regional Transmission Expansion Plan (RTEP), available at http://www.oe.energy.gov/DocumentsandMedia/pjm_3.pdf.

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- ⁵² American Electric Power Company, “The AEP Interstate Project Proposal: A 765 kV Line from West Virginia to New Jersey,” 2006. Available at http://www.aep.com/newsroom/resources/docs/AEP_InterstateProjectProposal.pdf.
- ⁵³ Vajjhalla, S. and P. Fischbeck, “Quantifying Siting Difficulty: A Case Study of U.S. Transmission Line Siting,” *Energy Policy*, 35:1 (2007) at 650-671.
- ⁵⁴ The language discussing so-called National Interest Transmission Corridors can be found in Section 1221 of the Energy Policy Act of 2005.
- ⁵⁵ *PJM 2005 State of the Market Report*, at Section 5.
- ⁵⁶ Alternative Portfolio Standards Act 73 P.S. § 1648.1 *et seq.* (2005).
- ⁵⁷ 66 Pa. C.S. § 2808.
- ⁵⁸ A third pollutant, mercury, is often included with SO₂ and NO_x in proposed three-pollutant or “3P” emission control regulations. Mercury controls are not part of CAIR.
- ⁵⁹ *Electricity Options for Large Industrial Customers in Western Pennsylvania*, *op.cit.*, Table 4.
- ⁶⁰ *Ibid.*, at p. 45.
- ⁶¹ The figure assumes fuel costs of \$7/MMBTU for natural gas, \$65/bbl for oil, and \$45/ton for coal. Hydroelectric and nuclear facilities are assumed to have variable costs of \$10/MWh. Wind and biomass facilities are assumed to have variable costs of \$40/MWh and \$50/MWh, respectively.
- ⁶² Spees, K. and L.B. Lave, *Impacts of Price-Responsive Load in PJM*, Carnegie Mellon Electricity Industry Center Working Paper CEIC-07-02 available at <http://wpweb2k.gsia.cmu.edu/ceic/publications.htm>.
- ⁶³ This calculation is done as follows. Retail sales in Pennsylvania total \$12.4 billion annually. 6% of this is \$744 million, the theoretical maximum real-time pricing savings. We assume half of this, or \$372 million actually is achieved. The cost for 5 million meters is \$1.3 billion, using the 2006 purchase by San Diego Gas & Electric of 5 million meters as a benchmark. If these were financed at 10% for 20 years, the annual amortization would be \$138 million per year. The net savings would be \$372 million less \$138 million, or \$234 million per year, 1.9% of total sales.
- ⁶⁴ Mid-Atlantic Distributed Resource Initiative Advanced Metering Working Group, “Installed Meter Survey Final Report”, April 27, 2005, at p. 8. Available at <http://www.energetics.com/madri/toolbox/pdfs/survey/survey.pdf>.
- ⁶⁵ Walawalkar, R., R. Tongia, and B. Colburn, “Web-enabled Metering and Controls for Demand Response” in *Information Technology for Energy Managers*: Vol. 3, ed. by B.L. Capehart; to be published 2007 by The Association of Energy Engineers.
- ⁶⁶ Covino, S., *Economic Load Response Summer 2000 Potential and Performance*, Presentation at the PJM Demand Response Working Group (November 2006), available at <http://www.pjm.com/committees/working-groups/dsrwg/downloads/20061130-item-09-summer-2006-performance.pdf>.
- ⁶⁷ Spees, K. and L.B. Lave, *Demand Response and Electricity Market Efficiency*, Carnegie Mellon Electricity Industry Center Working Paper CEIC-07-01, available at <http://wpweb2k.gsia.cmu.edu/ceic/publications.htm>.
- ⁶⁸ See <http://www.encyvermont.com>.
- ⁶⁹ “Energy Efficiency In A Needy State: How Efficiency Programs Helped the Vermont PSB Reduce the Burden of Electric Costs Even As Market Prices Rose”, seminar by M. Dworkin, November 1, 2006, Carnegie Mellon Electricity Industry Center, available at http://wpweb2k.gsia.cmu.edu/ceic/seminars11_01_06.htm.
- ⁷⁰ Gellings, C.W., G. Wikler, and D. Ghosh, “Assessment of U.S. Electricity End-Use Energy Efficiency Potential” *The Electricity Journal* 19:9 (November 2006) at 55-69.
- ⁷¹ Two behavioral possibilities exist for consumers to reduce demand. The first is for demand to be shifted from on-peak hours to off-peak hours. The second is that conservation or energy-efficiency

measures could reduce the total amount of demand for electricity. We calculated the effects of a demand reduction program focusing on conservation rather than load-shifting. Conservation efforts are assumed to reduce hourly demand by 5% in every hour of the year. For each of the Pennsylvania utility zones in which there is a defined LMP and hourly load data available (Duquesne, Allegheny, PPL, PECO), we use the econometric model developed to analyze the real time pricing option to estimate the relationship between hourly load and the hourly LMP in each zone between May 2005 and June 2006. The model was also used to estimate what the LMP would be if demand in each zone fell by 5% every hour of the year. Total estimated savings for all of PJM amounted to \$8 billion per year. Total estimated savings for Pennsylvania were \$1.9 billion per year. Allocating the Pennsylvania savings to commercial and industrial customers based on relative load, total annual savings to the commercial and industrial classes is \$574 million and \$646 million, respectively. Annual energy savings are 1.3 cents per kWh for both rate classes. Allocating the Pennsylvania savings to commercial and industrial customers based on relative revenue, total annual savings to the commercial and industrial classes is \$619 million and \$463 million, respectively. Annual energy savings for commercial and industrial customers is 1.4 cents per kWh and 0.9 cents per kWh, respectively.

⁷² New peaking generation would most likely be fueled by natural gas. We assume that a combined-cycle natural gas turbine running 20% of the time would have capital costs of \$800 per kW, and with a 6% capital charge rate (which assumes that the plants are financed through tax-free development bonds issued by the Commonwealth) would have average costs of 15.6 cents per kWh. A simple-cycle turbine running 5% of the time would have capital costs of \$400 per kW and average costs of 21.2 cents per kWh. PJM has 3.2 GW of generation with costs higher than the cost of a new combined-cycle turbine, and 73 MW of generation with costs higher than the cost of a new simple-cycle turbine. Assuming a 6% capital charge rate and a 30-year depreciation period, the annual capital expense for a combined-cycle plant would be \$58 per kW, and \$29 per kWh for a simple-cycle plant. Displacing existing high-cost peaking generation with combined-cycle technology would thus involve annual capital expenditures of \$186 million. Displacing only the “super peak” generation with new simple-cycle turbines would involve \$2 million per year in capital expenditures. The capital expenditure numbers we have used here are higher than the current values used in the Department of Energy – Carnegie Mellon University Integrated Environmental Control Model, but we have used these higher figures to obtain a lower bound on the calculated savings, and to allow for unforeseen cost increases. Based on 2005 data, the value of an *ad hoc* cap of \$150/MWh in the PJM market is \$4 billion. Pennsylvania’s load share of the PJM market is 22%, so Pennsylvania’s share of the savings is \$864 million annually. Allocating Pennsylvania’s savings to commercial and industrial customers based on load yields total annual savings of \$256 million for commercial customers and \$268 million for industrial customers. Annual energy cost savings are 0.58 cents per kWh for each of the commercial and industrial rate classes.

⁷³ \$1900 per kW, 6% capital charge rate with the state finance option, 30 years, 5% O&M, \$2/MMBTU coal, 80% capacity factor, 12% profit on the invested capital.

⁷⁴ U.S. Environmental Protection Agency’s Emissions & Generation Resource Integrated Database (eGrid) 2006, with data from 2004. Available at <http://www.epa.gov/cleanenergy/egrid/index.htm>.

⁷⁵ Talukdar, S., L. Lave, Lye, K.W., Marshall, K.C., and Subrahmanian, E. (2003). “Agents Evolutionary Learning And Market Failure Modes”. Hawaii International Conference on Systems Science, Manoa, Hawaii, Computer Society Press.

⁷⁶ The proposed new auction model for PJM would replace the uniform-price auction with a series of cost-based long-term contracts. The savings from switching to this new auction would thus be equal to the total payments to generators over and above marginal cost in the current auction, minus the average-cost payments in the new auction. We have used hourly load and LMP data for PJM in 2005

to calculate, for each hour, the marginal cost of serving the load and the LMP for that hour. The difference between the LMP and the marginal cost (multiplied by the load in that hour) gives the excess payments above marginal cost. To calculate what the payments would be under the new auction model, we recalculated the PJM marginal cost curve assuming that existing generation would have to receive the average cost of a new plant as an incentive to sign long-term contracts with PJM. These new plants would not need to replicate the existing PJM generation mix. Existing hydroelectric, coal, nuclear, and gas baseload plants would be offered contracts based on the average cost of a new supercritical pulverized coal plant. We assume the average cost of such a plant to be 5.4 cents per kWh. Shoulder plants (a mix of natural gas and some oil) would be offered contracts based on the average cost of a combined-cycle natural gas turbine, assumed to be 15.6 cents per kWh. Peakers (primarily oil with some natural gas) would be offered contracts based on the average cost of a new simple-cycle natural gas plant, which we assume to be 21.2 cents per kWh. We then calculated the total cost of serving the PJM load in each hour using this new marginal cost curve. The difference between the excess energy payment and the new total cost represents the savings from the new auction structure. Total annual savings to PJM is \$3.7 billion. Pennsylvania's share of the savings is \$806 million. Allocating the savings to Pennsylvania commercial and industrial customers based on relative load, total annual savings to the commercial and industrial classes is \$239 million and \$269 million, respectively. Annual energy savings amount to 0.5 cents per kWh for both customer classes. Allocating the savings to Pennsylvania commercial and industrial customers based on relative revenue shares, total annual savings to the commercial and industrial classes is \$257 million and \$193 million, respectively. Annual energy savings for the commercial and industrial classes are 0.6 cents per kWh and 0.4 cents per kWh, respectively.

⁷⁷ This calculation assumes a combined cycle natural gas plant based on the GE Frame 7 design as modeled in the Integrated Environmental Control Model (IECM), using a natural gas price of \$7 per million BTU, operating at a 75% capacity factor.

⁷⁸ Connecticut Act 05-01, see <http://www.connecticut2006rfp.com/>.

⁷⁹ See King, D. and M.G. Morgan, *Guidance for Drafting State Legislation to Facilitate the Growth of Independent Electric Power Micro-Grids*, Carnegie Mellon Electricity Industry Center Working Paper CEIC-03-17, available at <http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-03-17.asp>.

⁸⁰ "Southwest Indiana aims to be home to large natural gas plant", press release October 27, 2006, Governor Mitch Daniels, Evansville, Indiana. Available at <http://www.in.gov/apps/utis/calendar/presscal?PF=gov2&Clist=196&Elist=87587>.

⁸¹ Rode, D.C. and P.S. Fischbeck, *The Value of Using Coal Gasification as a Long-Term Natural Gas Hedge for Ratepayers*. 2006, Carnegie Mellon Electricity Industry Center Working Paper CEIC-06-12, available at <http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-06-12.asp>.

⁸² Gasification Technologies Council, Online Gasification Database. <http://www.gasification.org/resource/database/search.aspx>.

⁸³ Bartik, T.J. "The Effects of State and Local Taxes on Economic Development: A Review of the Recent Research." *Economic Development Quarterly*. Vol. 6, No. 1, February, 1992.

⁸⁴ Bartik, T.J. "Who Benefits from Local Job Growth: Migrants or the Original Residents?" *Regional Studies* 27:4, 1993.

⁸⁵ Buss, T., "The effect of state tax incentives on economic growth and firm location decisions: an overview of the literature," *Economic Development Quarterly*, Vol. 15, 2001; Ady, R., "Taxation and Economic Development: The State of the Economic Literature," *New England Economic Review*, Federal Reserve Bank of Boston, March/April 1997.

⁸⁶ Pennsylvania Act 89–2002. See <http://www.revenue.state.pa.us/revenue/cwp/view.asp?A=11&Q=36886>.