Comments of Constellation Energy Commodities Group, Inc.
Concerning Recent Procurement Events Held On Behalf of
Commonwealth Edison Company and the
Ameren Illinois Utilities (Ameren-CILCO, Ameren-CIPS, and Ameren-IP)

Section 16-111.5 of the Illinois Public Utilities Act (the "Act") includes various provisions relating to the procurement of electric power and energy for Commonwealth Edison Company ("ComEd"), as well as Central Illinois Light Company (d/b/a AmerenCILCO), Central Illinois Public Service Company (d/b/a AmerenCIPS), and Illinois Power Company (d/b/a AmerenIP) (collectively, the "Ameren Illinois Utilities"). Among those provisions are requirements for ComEd and the Ameren Illinois Utilities to file procurement plans for electric power and energy acquisition for those customers that are eligible to take fixed-price electric service from ComEd and the Ameren Illinois Utilities for the supply period of June 1, 2008 – May 31, 2009 ("Initial Procurement Plans"). Consistent with the Act, ComEd and the Ameren Illinois Utilities filed Initial Procurement Plans with the Illinois Commerce Commission (the "ICC" or "Commission"). Those Initial Procurement Plans were open to comment and debate by interested parties before the Commission. In the Commission proceedings, certain aspects of the Initial Procurement Plans, such as the development of standard contract forms, were subject to input from Commission Staff and other interested parties. At the conclusion of those proceedings, the Commission entered Orders approving the Initial Procurement Plans (ICC Docket Nos. 07-0527, 07-0528, and 07-0531).

Pursuant to those Orders, ComEd and the Ameren Illinois Utilities engaged third-party procurement administrators to conduct their respective Initial Procurement Plans pursuant to sealed-bid requests for proposals ("RFPs") for energy, capacity (Ameren only), and Renewable Energy Certificates ("RECs"). The Results of the five (5) RFPs were approved by the Commission after being supervised by a Commission-hired procurement monitor, Boston Pacific Company, Inc.

In addition to review and approval of the Initial Procurement Plans, Section 16-111.5(o) of the Act states:

> On or before June 1 of each year, the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change.

In fulfillment of this requirement, the Commission provided public notice dated April 10, 2008, of its intent to hear all interested parties' comments relating to the above-described procurement process and its five procurement events.

<u>Background</u>

Constellation Energy Commodities Group, Inc. ("CCG") is a power marketer authorized by the Federal Energy Regulatory Commission to sell energy and capacity and certain ancillary services at market-based rates. CCG focuses on serving the needs of distribution utilities, co-ops and municipalities that competitively source their load requirements. CCG also sells natural gas and other commodities at wholesale, both in the United States and abroad, and holds interests in exploration and production companies. CCG does not own any physical assets for the generation, transmission, or distribution of electric power and has no retail electric customers or service territories. However, CCG bids energy, capacity and ancillary services on behalf of generation-owning affiliates into the markets administrated by PJM Interconnection, L.L.C. and the Midwest Independent Transmission System Operator, Inc.

Summary of Recommendations

CCG was an active participant in the Commission proceedings that resulted in the adoption of the Initial Procurement Plans as well as all of the related activities conducted by the Procurement Administrators leading up to each of the five procurement events currently under review. CCG submitted bids in each of the five procurement events, and was one of the winning bidders in four of those events. Based on its experiences in the recent procurement events, as well as its expertise over the years in other procurement events in Illinois and other jurisdictions, CCG proposes the following three (3) overarching recommendations for improvements to the future procurement processes to be overseen by the Illinois Power Agency ("IPA"):

1. Reduce regulatory uncertainty by shortening the window of time between submission of bids and execution of contracts with winning suppliers, and providing clear standards for review of procurement results by the ICC;
2. To the extent possible, achieve standardization for all procurement events; and
3. Include full requirements contracts in procurement plans.

Reduce Regulatory Uncertainty

The time period between the submission of bids and the execution of contracts with winning suppliers should be shortened, to the extent possible, and clear standards should established for the acceptance or rejection of bids.

Shorten the Period of Time Between Bids and Contract Execution

Under the Act, the procurement administrator must provide a confidential report to the ICC within two (2) business days after opening of sealed bids, the ICC shall accept or reject the recommendations of the procurement administrator within two (2) business days after receipt of the confidential reports, and the utility shall enter into binding contractual arrangements with the winning suppliers within three (3) business days after the ICC decision. 220 ILCS 5/16-111.5(f), (g). Thus, there may be a total of seven (7) business days between the date on which bids are submitted and the date on which the contracts are executed by the winning suppliers. However, this timeline could potentially stretch to twelve (12) calendar days, given weekends and holidays.

The longer that bids must remain open, and be subject to the possibility that bids will be renegotiated or rejected during a review process that does not define the criteria for such renegotiation or rejection, the greater the likelihood that consumers will ultimately be economically harmed. While bids are held open during the review process, bidders retain the risk that market prices will change suddenly or unexpectedly. This risk is particularly important in procurement events involving Block Energy Products, given the volatility in today's market. Potential suppliers have to incorporate such risks in their bids to account for this time lag. These risks will necessarily translate into bid prices.

Decreasing the length of time between submission of the bid and ultimate contract execution decreases the risk that suppliers bear, which would likely lead to lower overall bid prices. Such a result is consistent with the legislative mandate that:

> The Commission shall approve the procurement plan if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service **at the lowest total cost over time**, taking into account any benefits of price stability.[1]

Given that the Block Energy Products are standard wholesale energy products, the review of these bids should be relatively straightforward, and should not require negotiation or additional review time.

[1] 220 ILCS 5/16-111.5(d)(3) (emphasis added).

Establish Greater Clarity and Standards For Evaluation of Bids

The Act does not provide clear and well-defined standards that are to be used by the Procurement Administrator and the Commission to evaluate the bids, which increases the risks that are translated into bid prices. The Act also grants the Procurement Administrator the discretion to re-negotiate the prices of bids that meet the benchmarks approved by the Commission.[2] CCG is not aware of any other jurisdiction that relies upon competitive wholesale procurement that allows re-negotiation of prices after submission of bids. The competitive wholesale procurement processes utilized in D.C., Delaware Connecticut, Maine, Maryland, and Pennsylvania do not contain such a provision. That is not surprising, given the fact that such a provision unnecessarily increases the risks that a potential supplier must bear before bids are approved, which suppliers must factor into their bid prices. In addition to the ambiguity of pricing remaining "open" for a day after the bids are submitted, the Act does not set forth clear standards for the Procurement Administrator's recommendation for the acceptance and rejection of bids. Instead, it indicates only that recommendations should be based on "the price benchmark criteria and other factors observed in the process"[3]. Similarly, the Act does not set forth any criteria for the Commission's acceptance or rejection of the Procurement Administrator's recommendations.[4]

A potential solution to the above concerns can be addressed with three straightforward changes to future procurement events. **First,** winning and losing bidders should be notified by the Procurement Administrator, subject to ICC approval, as soon as possible on the same calendar day that bids are submitted. As stated above, the review of

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[2] 220 ILCS 5/16-111.5(c)(1)(vii).
[3] 220 ILCS 5/16-111.5(f).
[4] *Id.*.

bids for standard Block Energy Products should be relatively straightforward, and should not require additional time. At a minimum, bidders should receive notification of the Procurement Administrator's recommendation to the ICC at substantially the same time that the recommendation is delivered to the ICC. This process was followed throughout the ComEd procurement processes, but was not followed in the Ameren procurement processes, despite requests from several potential bidders. This is of particular importance for the energy procurement, in which there is the greatest price volatility.

Second, there should be a shorter time period between the submission of bids and ultimate approval by the Commission, as well as final execution of contracts with ComEd and the Ameren Illinois Utilities. As described above, given the fact that bids submitted will involve standardized products, bids should be approved as soon as possible, and contracts should be executed within one (1) business day following Commission approval. Indeed, the procurement administrators, the ICC, and the utilities were able to act more quickly than permitted under the Act in the most recent procurement events.

Third, the permissible grounds for recommending rejection of a bid, and the Commission authority to reject bids, must be clear, well-defined and focused on whether the approved procurement process had been followed and potentially other defined objective criteria, rather than extraneous or subjective criteria. Further criteria are extraneous when a procurement process is properly designed to be competitive and when bids from qualified participants are recommended by Procurement Administrators for Commission approval only on a lowest-price basis (rather than other discretionary characteristics), where the lowest-prices also must meet Commission-pre-approved benchmarks. Causes for rejection by the Commission should be limited to narrow and objective criteria made publicly available well in advance of bid submissions, in order to minimize the regulatory risk to the greatest extent possible. Specifically, the Commission should reject the results of a procurement event only if the administrators and utilities have not correctly implemented the Commission's pre-approved procurement plans (including use of the pre-approved benchmarks). To summarize, a Procurement Administrator should recommend bids for approval by the ICC based on the following criteria alone: (1) affirmation that the recommended bids were submitted in compliance with the Commission-approved procurement process and rules, (2) finding that the recommended bids meet the Commission's pre-approved market price benchmarks, and (3) finding that the recommended bids have the lowest price(s) among the submitted sealed bids. In this way, the Commission will be able to approve the Procurement Administrator's recommendation as submitted, upon a determination that the procurement event was run in compliance with the procurement process and rules.

Reduce Administrative Burden Through Standardization

Future procurement events can benefit from standardization in several areas. In the recent procurement events, there was a dramatic difference between the requirements, documents, and processes that were utilized by ComEd and the Ameren Illinois Utilities and their respective Procurement Administrators. For example, ComEd and the Ameren Illinois Utilities utilized two completely different websites. Also, bidders were required to complete the same documentation and/or training for each procurement event, even for those being conducted for the benefit of the same utility. Therefore, bidders were required to review documents that were often very different, although the procurement events were being conducted for identical or very similar products. Consequently, entities that planned to participate in each of the recent procurement events were required to attend five different bidder training sessions on bid submission. All of those differences and redundancies placed greater administrative burdens on potential bidders, without aiding the efficiency of the procurement events, or their ultimate results.

The below list identifies the requirements, documents and processes that should be identical for future procurement events, to the greatest extent possible.

- Confirms & Contracts – Contracts for same products should be identical, such as those for RECs. Contracts for different products should include the same provisions to the extent possible;
- Prequalification Requirements;
- Pre-Bid Letter of Credit ("LoC") – Ideally, prospective bidders should be required to fill out only one pre-bid LoC, which would be used for each procurement event in which they were bidding;
- Post-Bid LoC – As with the pre-bid LoC, one post-bid LoC should be used for a single bidder for all procurement events;
- Bid Form;
- Bid Submission process; and
- Bidder Training – Standardizing of the above should ideally lead to the situation in which a prospective bidder need only attend one bidder training session.

<u>Use Full Requirements Products To Minimize Customer Risks</u>

The IPA should conduct future procurement events that rely upon the use of full requirements products. The IPA is given discretion to procure products individually, or in combination.[5] The IPA should take into consideration the fact that customers bear greater risk with separate block products, because the shape and quantity of the load is not known, and should adjust future procurement plans accordingly by procuring full requirements contracts.

[5] 220 ILCS 5/16-111.5(b)(3)(iii).

Procuring full requirements contracts achieves several benefits. First, a full requirements procurement structure relieves the IPA from active portfolio management responsibility, and instead places the planning responsibility into the hands of the winning full requirements suppliers, who have extensive experience in managing portfolios. In doing so, full requirements procurement demands far less regulatory involvement in evaluating the specifics of a procurement plan to assess whether the IPA is buying the "right" products, in the "right" amounts, and at the "right" times, than would an approach for Block Energy Products. Second, this approach yields the lowest fixed price at which these customers can be served, so it provides a fully competitive price while at the same time minimizing short term price volatility and insulating customers from other risks that would be borne by the full requirements suppliers. Third, it will continue to offer an efficient way to bring the benefits of wholesale competition to residential and small commercial customers that do not select alternative retail electric suppliers. A new independent study was issued in January 2008 ("2008 Market Study") by the Analysis Group, a well-respected energy and economic consulting firm; it promotes the use of competitive procurements for full requirements contracts. The 2008 Market Study points out that:

> One of the advantages of competition in the procurement of such [full requirements service] is that it taps into the abilities and skills of different players to develop different and innovative strategies to meet and adapt to power supply conditions as they change in the future. This provides a diversity advantage to consumers. It passes risk from consumers and the utility that is serving as their supply conduit over to the third party supplies.[6]

[6] *See Pennsylvania's Electric Power Future: Trends and Guiding Principles*, Susan F. Tierney, Ph.D., Analysis Group (January 2008) ("2008 Market Study") at p.11.

A copy of the 2008 Market Study is attached to these comments. While the 2008 Market Study was prepared to provide recommendations to Pennsylvania – because that state over the next several years will be making decisions about individual utilities' default service procurements – it provides useful analysis to consider in jurisdictions like Illinois that rely upon competitive wholesale procurement, especially where the IPA will be starting with a clean slate to determine how best to meet the future default procurement needs of Illinois' electric utilities. Of particular importance in the 2008 Market Study is its finding that:

> In states with retail choice where the local distribution company focuses of "delivering" power and no longer carries out generation functions, the utility no longer has comparative advantages in power markets. Here, the utility provides a basic product – "full-requirements generation service" – and [serves] as the conduit for these customers in the competitive market place. In this conduit role, the utility calls upon third-party suppliers to provide all of the necessary components of providing supply to customers: energy, capacity, ancillary and other services (such as meeting Alternative Energy Service requirements) at all times and at all levels of customer demand over the course of a day or a season. **The utility can make good use of competitive markets to find lowest-cost supplies of "full requirements" power to meet the needs of basic generation service customers; it can do so by defining the product it purchases from competitors, rather than choosing the individual components of a particular portfolio of generation resources used to provide the product.** It is the experienced participants in wholesale markets who take on the tasks of developing a portfolio of resources, making physical arrangements to lock-in certain supply, arranging for transmission of the supplies, making financial arrangements to hedge their financial and price risk, and offering to sell at a fixed price offer in competition with other suppliers.[7]

Similarly, the IPA can best access competitive wholesale markets by procuring full-requirements products, rather than by trying to purchase individual components of service (*i.e.*, energy, capacity, RECs, etc.) on its own.

[7] 2008 Market Study at p.11 (emphasis added).

Conclusion

Constellation recommends that future procurement plans and procurement events conducted by the Illinois Power Agency and evaluated by the Commission reflect these improvements to the procurement process.

Respectfully Submitted,

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Pennsylvania's Electric Power Future: Trends and Guiding Principles

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PENNSYLVANIA'S ELECTRIC POWER FUTURE: TRENDS AND GUIDING PRINCIPLES

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January, 2008

EXECUTIVE SUMMARY

Pennsylvanians have benefited from stable electricity prices over the past decade – a situation enabled to a large degree by a package of reforms adopted by the General Assembly in the Commonwealth's Electric Generation Customer Choice and Competition Act of 1996. When that law was passed, Pennsylvania's electricity rates were among the highest in the country. Over the past decade, consumers in most other parts of the country have seen their electricity prices rise much higher than in Pennsylvania. In fact, price increases in Pennsylvania have been relatively small, at one-half the rate of inflation. Unlike a decade ago, Pennsylvania's electricity rates are now lower than the national average. Studies show that competitive markets have introduced positive changes in the states where restructuring has occurred. Pennsylvania policy makers should stay the course and support the development of competitive markets in the Commonwealth.

Looking ahead as rate caps for the remaining Pennsylvania electric utilities expire, various stakeholders have been exploring the best ways to help steer the state's passage through the upcoming transition to a world of relatively higher electricity prices that reflect the current cost of supplying electricity. The Pennsylvania Public Utility Commission, for example, with the participation of various consumer, utility, power suppliers, environmental, and others, recently adopted a strategy for preparing Pennsylvanians to understand and mitigate the impacts of future increases in power supply costs. Governor Rendell and the Pennsylvania General Assembly are considering ways to educate consumers, provide tools for enabling consumers to manage their energy use, and ensure increased reliance on competitively sourced alternative energy products.

Readying consumers for a future reflecting current energy-market conditions is key for leaders in the Commonwealth. Taking the right steps will require an understanding of some of the underlying trends and opportunities for prudent leadership. This should involve resisting – for all the right reasons – the natural tendency to want to "fix" prices when they rise. And Pennsylvanians will become better able to manage their energy use in the future if they are equipped with the right tools to do so.

This paper is designed to provide some information and guidance as Pennsylvania looks ahead to its power future. The paper does so by explaining first some of the defining trends in the electric industry, and then provides four principles to help guide the Commonwealth's path toward reasonable approaches for determining electricity pricing and procurement in the years ahead.

Trends and guiding principles for PA's electric future

Explained more fully below, several defining trends in the electric industry are as follows:

- **Restructured power markets have provided measurable benefits for consumers**. These benefits include those identified as goals in Pennsylvania's own Electricity Generation Customer Choice and Competition Act of 1996: to rely on "competitive market forces [which] are more effective than economic regulation in controlling the cost of generating electricity," to bring about innovation and improvements in risk management; and to allow consumers to make choices about their power suppliers. Other outcomes have included greater development of renewable resources and technologies designed to assist consumers to reduce their demand for power.

- **Even so, higher electricity prices are occurring in both regulated and restructured states, and the result of fundamental changes in global markets for fossil fuels.** Higher prices also stem the need to address other critical economic and social challenges such as reducing greenhouse gas emissions from power production, continued demand for reliable power, and aging infrastructure.

- **Electricity still provides high value, with prices much lower today than they were 20 years ago, when adjusted for inflation**. Compared to many other goods and services we depend upon in our daily lives, electricity still remains a relative bargain. Across the U.S., taking inflation into account, prices are still only about 2/3rd of what they were at their highest in the early 1980s. Similarly, as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than it did during the 1980s. Electricity prices have risen more slowly than those for other goods and services (especially including heating oil, gasoline, and natural gas delivered to commercial users and to home). At the same time, more electricity is being used than in the past, as we depend upon electronic systems for more of our basic services.

With these trends in mind, several reasonable principles can help Pennsylvanians' transition to the next chapter of the Commonwealth's electric industry and to ready them for what will be required to help keep Pennsylvania's economy vibrant, and innovative. These principles are summarized here and explained in greater detail below.

- **Pennsylvania policy makers should continue to support competitive markets; a stable regulatory environment will attract capital investment needed to meet Pennsylvania's power requirements.** The Commonwealth's economy, and its goals for an innovative and modern energy sector, depend upon attracting capital. Building on the current regulatory and market structure, and making incremental policy changes (rather than substantial redesigns of the industry) will help create the investment climate needed for Pennsylvania to achieve its energy goals.

- **Policy makers should heed the lessons learned when rate freezes were imposed at levels out of line with market conditions**. California's ill-fated electricity crisis in 2000-2001 was made worse when state policy makers continued retail price caps at a time when electricity companies had to buy power at much-higher wholesale market rates. After Pennsylvania's rate freezes expire in upcoming years, those companies cannot avoid obtaining power at current market prices. At that point in time, extending rates at current levels would be identical to imposing entirely new rate raps, since those rates reflected agreements and conditions designed for a fixed transition period. California's experience warns that keeping rate freezes in place when utilities must procure power at costs well above the rap cap would impose dire financial consequences for those companies, send signals to investors that are opposite from the investment-friendly climate the state hopes for, and will raise costs to consumers in the long run.

- **Other available tools, not rate caps, can help electricity consumers manage their energy needs in the future**. Adopting new regulatory policies that support electric companies providing electricity customers with the kind of information, service and product options, and other types of assistance they need will help Pennsylvanians better manage their energy needs and control their electricity expenditures in the 21st century. Among the policies to support this result are well-designed phase-in mechanisms to bring customers' rates gradually to market prices, instituting incentives for adoption of advanced metering, use of better pricing options, services and technology packages to enable electricity customers to better manage their own demand and thus allow the chance for more vibrant retail choice to develop, and providing programs to assist low-income customers.

- **Well-designed power market policies and rules matter, for keeping prices to consumers as low as possible.** These policies and rules are still evolving, and include well-designed and implemented competitive power procurement processes that enable electric distribution utilities to obtain power supplies for those customers who do not elect to buy power from a competitive supplier. Great attention still needs to be paid to refining these and other policies to help Pennsylvania move through this transition and allow its citizens to get the benefits of a clean, efficient, reliable, and more secure electricity future.

So, while we can expect a "new normal" of higher electricity prices in the electric industry for the foreseeable future, we can also hope for a strong electric industry, able to provide Pennsylvanians with the energy infrastructure and services they will need. Presuming a degree of regulatory and policy stability going forward and reliance to a considerable degree on market forces, we can expect private investors to supply capital for the grid, for greater improvements in energy efficiency, and for development of more innovative power production facilities consistent with a carbon-constrained economy. And we can expect electricity users to have the information, services, and technologies they will need to better manage their own power needs and keep electricity as affordable as possible. All of this is good for consumers.

KEY TRENDS IN THE ELECTRIC INDUSTRY

1. RESTRUCTURED POWER MARKETS HAVE PROVIDED MEASURABLE BENEFITS FOR CONSUMERS.

Since restructuring its electric industry a decade ago, Pennsylvania, like the other third of the states that did the same, has a different electric industry and system today than it did in the past. Pennsylvania's policies allow suppliers other than electric utilities to provide power to consumers, afforded non-utility generators the opportunity to buy utility power plants, opened up and created incentives in the power sector for greater competition, investment and performance efficiencies, moved to market mechanisms as the means to set electricity prices, and so forth. Many regions (including the PJM power region, in which Pennsylvania is located) developed Regional Transmission Organizations ("RTOs") to independently operate the grid and to administer wholesale power markets, using them to determine efficient dispatch as well as market-clearing prices.

For the most part, the states that pursued early efforts to restructure their electric industries were ones that (like Pennsylvania) already had high electricity prices during the 1990s. These were states where at the time, a number of features — rate increases associated with new power plant investment, cost overruns, expensive long-term contracts, combined with opportunities to build new generating capacity at costs lower than prevailing electricity prices — motivated large electricity consumers (and their political representatives) to complain about utilities' high price levels under traditional regulation and seek the option to buy power directly from the electricity supplier of their choice. Almost all of the states that now have higher-than-average retail electricity rates were also among the states with higher-than-average rates on the eve of restructuring the electric industry in 1996.[1] Over the past decade, the gap has narrowed between the prices in the high-cost states that restructured and the prices in the states that did not.[2]

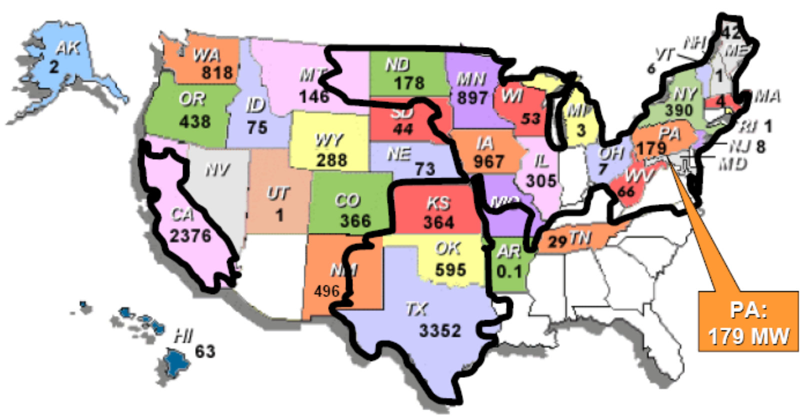
There were many motivations at the roots of these past efforts to introduce competition into the electric industry. As Pennsylvania's electric competition act declared, "competitive market forces are more effective than economic regulation in controlling the cost of generating electricity." There were desires to reduce the influence of utilities' preferences for rate-base investments over other alternatives that might have provided greater consumer benefits; hopes to bring about innovation and improvements in risk management; and the goal of allowing consumers to make choices about their power suppliers. To date, some of these benefits have transpired; others are still a work in process.[3]

For example, the nation's overall mix of power plants is now much more efficient than in the past. Today's markets have provided incentives for producers to make needed investments and improvements in operating practices, with cost savings[4] and other improvements resulting in increases in the efficiency of fuel-consumption of fossil fuel-fired facilities;[5] decreases in the length of refueling outages, lower operations and maintenance expenses, and greater plant availability at nuclear facilities;[6] and decreases in operations and maintenance costs across all facilities.[7] Improvements that increase plant availability are particularly valuable because they increase the quantity of power produced by less-costly power facilities.[8] Also, restructured wholesale markets have improved the efficiency by which plants are "dispatched" (i.e., turned on and off) to meet consumer demand.[9] Certain long-standing barriers to efficient trade across regions (e.g., "pancaked" layers of transmission rates needed to transport power across multiple regions) have been reduced or eliminated, helping to reduce overall power costs.[10] Adding newer more efficient power production technology and dispatching the system more efficiently has led to reductions in air emissions from power plants in some competitive electric markets.[11]

Competitive power markets have also led to greater "demand response." On August 8th, 2007, for example, retail customers in the PJM region voluntarily reduced their demand by nearly 2,000 MW – an amount roughly equivalent in size to two large nuclear power plants, or enough to meet the needs of approximately 1.5 million homes – in response to real-time price signals in PJM's wholesale market. These customers were paid for the "resource" (reduced demand) that they provide to the system which in turn provides economic benefits to other consumers.[12] Without this "demand response," other more expensive power supplies would have had to be dispatched, or PJM might have had to resort to involuntary disruptions of service to customers. New York's and New England's RTOs have seen similar success in demand-response programs. In New England, some providers of energy efficiency programs are bidding those "saved megawatts" into the electric capacity markets, providing the "efficiency suppliers" with payments that are then used to finance the delivery of efficiency technologies into homes, offices, and other buildings.

Renewable power resources (like wind projects) have been added principally in parts of the country served by RTO-administered markets (such as PJM, serving the Pennsylvania power market). (See Figure 1.) In addition to being regions where states have adopted "renewable portfolio standards", these regions also have much-more-favorable transmission policies that enable suppliers to obtain delivery capacity, the visibility of prices by location and time of day, and the ability to sell into spot markets and/or multiple buyers.

Figure 1:
Total Installed U.S. Wind Energy Capacity (MW) in each state as of June 2007
(Border of regions in RTOs is shown in bold black outline)



Source: http://www.awea.org/utility/wind_overview.html (total wind capacity = 12,634 MW as of June 30, 2007)
http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp (RTOs as of September 2007)

Also, in states with retail choice, many customers have opted to manage their own power supplies — determining their supplier, managing their demand, and hedging their price risks.[13] In most parts of Pennsylvania and in many other states where rate caps have been (or are still in place),[14] it is mainly large and relatively sophisticated electricity customers (such as universities, factories, large and small stores) that have opted to buy from a competitive supplier. As rate caps have expired in states around the country (and in parts of the Commonwealth), other consumers have chosen to buy power from a competitive retail supplier.[15] While consumers in those states that now see full market prices are paying more for their electricity, there are good examples around the country of states (e.g., New Jersey, Massachusetts) where proactive communications, combined with well-planned measures to phase-in and blend-in higher market prices, have allowed a smooth transition from capped rates to today's prices.

2. HIGHER ELECTRICITY PRICES ARE OCCURING BOTH IN STATES THAT RESTRUCTURED THEIR ELECTRIC INDUSTRIES AND THOSE THAT DID NOT.

Around the country, higher electricity prices are the "new normal" for most Americans. No consumer likes price increases of any kind, let alone those we feel we can't control and for things – like electricity – we absolutely need. We depend upon having electricity, whenever we need and want it to power so many activities essential (and not so essential) to our daily lives. Our modern society has such a deep dependency on electricity, not just for basic necessities like light and cooling and communications, but for all of the wonderful devices and gadgets it powers. Because we tend to take reliable power supply for granted, we somehow also expect to have it at low rates.

But the reality of conditions in today's global energy markets make it unlikely that low electricity prices will prevail in the future, in Pennsylvania or anywhere in the U.S. The average American has seen prices go up about a third over the past decade. The price of power has been rising for several reasons. Fossil fuels — that is, natural gas, oil, and coal supplies, which together produce over 70 percent of the nation's power[16] — have had significant price increases in the past few years after a period of comparative calm during the 1990s. Natural gas prices shot up starting in late 1999, as North American markets tightened. While natural gas prices have dropped since they spiked following the Hurricanes of 2005, they still remain relatively high, and are not likely to drop any time soon. Even coal — the lowest-cost fossil fuel, used to produce over half of the power generated in the U.S. — has experienced 40-percent price increases since 2000.[17] Electricity prices generally track changes in fossil fuel prices over time, with prices beginning to rise starting around 2000.[18]

Increases in fossil fuel prices affect electricity prices differently in different parts of the nation, because of regional differences in the fuels used to generate power. Regions (like New England, California, and Texas) that rely significantly on natural gas to produce power have relatively high electricity prices, while other parts of the country (such as the PJM region (which includes Pennsylvania), the South, and the Mountain states) that produce more than 50 percent of their power from coal have among the lowest electricity rates in the country. Nearly all of the 30 states (like Pennsylvania) with below-average electricity rates in 2006 are in regions with a high percentage of power produced by coal.[19]

Other things also contributed to high electricity prices. New investment has been needed to keep the lights on and reduce environmental impacts from generating electricity. From 2000 to summer of 2007, U.S. households, businesses, factories and others together increased use by more than a state of Texas-sized amount of new demand.[20] During that period, more than 210,000 MW of new power plant capacity went into operation – roughly equivalent to adding one large power plant a week over the entire period.[21] Using a conservative, back-of-the-envelope estimate, this represents an investment of roughly $100 billion across the country, just to keep pace with new demand and plant retirements.[22]

Other costs have also begun to drive up electricity prices. From 2002 through 2005,[23] electric companies spent more than $21 billion to comply with federal environmental laws adopted to address health problems associated with air and water pollution. These costs have already begun to show up in electricity prices. Utilities' annual investment in transmission and distribution systems amounted to approximately $24.2 billion in 2006, up from $10.4 billion in 1995.[24] Over 2,500 miles of high voltage transmission lines were added in 2005 alone — equivalent to a new line stretching most of the way across the U.S.[25] The price of construction materials (like iron, steel, cement and concrete) has risen sharply in recent years, further increasing costs to build energy facilities.[26]

The effects of these factors are likely to persist for the foreseeable future. Electricity prices, like fossil fuel prices, are expected to remain high in the near and longer term.[27] The same is true for investment requirements. The U.S. government estimates that 258,000 MW of new capacity is needed between 2006 and 2030, equivalent to four new "Texan"-size electrical additions and a total investment of $412 billion (2005 dollars) — or even higher, if today's high construction-related cost increases continue.[28] Further, grid operators are seeing significant new investment requirements to expand and upgrade regional power service.[29] Installing more advanced metering, energy efficiency and other demand-side technologies to enable consumers to see and better manage their electrical use and even avoid the need for new power plants also come at a cost. Meeting existing clean-air regulations will cost the electric industry an additional $2.7 billion a year in 2010, and $4.4 billion in 2015.[30] And the cost of controlling carbon emissions from electricity production and use (which account for approximately 40 percent of U.S. CO^2 emissions, or nearly 10 percent of worldwide CO^2 emissions[31]), will inevitably increase in the future, and indeed need to begin to show up in prices in order to induce the kind of technological innovation required to meet the nation's electricity needs in a carbon-constrained world.

In light of these costs, it is simply unrealistic to expect that electricity prices are going to be lower in the near future. It seems reasonable to equip Pennsylvanians with this information so that they can begin to prepare for a different set of conditions in the future than they enjoyed in the past.

3. ALTHOUGH PRICES ARE RISING, ELECTRICITY STILL PROVIDES HIGH VALUE.

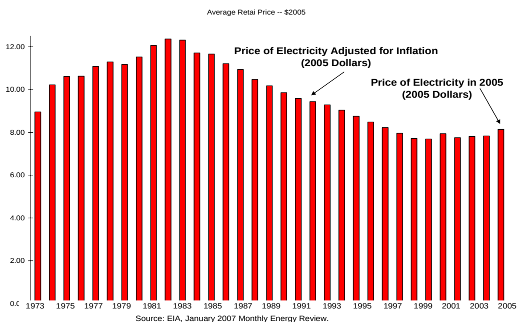
Compared to many other goods and services we depend upon in our daily lives, electricity still remains a relative bargain. Across the U.S., taking inflation into account, prices are still only about 2/3rd of what they were at their highest in the early 1980s. (See Figures 2.a and 2.b, below.) Similarly, as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than it did during the 1980s. Electricity prices have risen more slowly than those for other goods and services (see Figure 3). And from 1999 through 2006, electricity price increases were far lower than those for heating oil, gasoline, and natural gas delivered to commercial users and to home.

In fact, households spend no more (as a percentage of median income) on electricity than they did a decade ago, yet the average American is using much more electricity than in the past.[32] That we use more power today is hardly surprising, given the significant increase in electronic consumer products and in the many technologies and tools in our offices, shops and factories that depend on reliable electricity supplies. Every cell phone charger, every plasma TV, every computer, every ATM, every new cooler at the local convenience store, and every air conditioner adds to our power requirements. Overall, our standard of living depends on having access to electric power.

Figure 2

Average All-In Retail Price of Electricity (Including Fuel Costs), 1973-2005

Price of Electricity (adjusted for inflation)
Figure 2.a



Price of Electricity (real dollars)
Figure 2.b

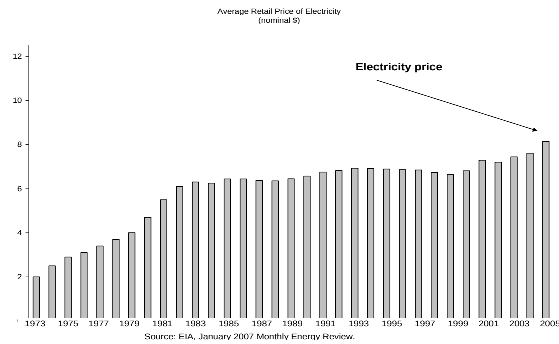
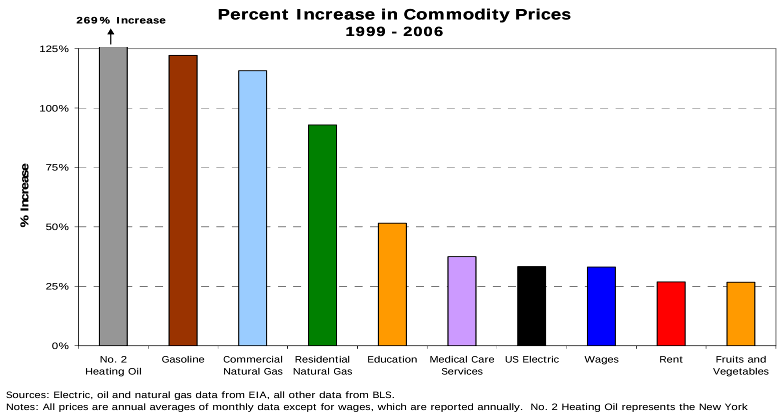


Figure 3



IMPORTANT PRINCIPLES TO GUIDE THE TRANSITION TO THE NEXT CHAPTER OF PENNSYLVANIA'S ELECTRIC INDUSTRY

1. STAYING THE COURSE AND SUPPORTING COMPETITIVE MARKETS WILL HELP PENNSYLVANIA ATTRACT THE CAPITAL INVESTMENT NEEDED TO MEET ITS NEEDS FOR CLEAN, RELIABLE AND AFFORDABLE POWER AND TO ASSIST CUSTOMERS IN MANAGING THEIR OWN ELECTRICITY BILLS.

At the end of 2007, across the U.S., the electric industry finds itself in a situation where approximately one-third of the states (representing 2/5 of the sales of electricity around the country) are now pursuing a competitive market model for the electric industry in their state. These restructuring reforms tended to occur in states, like Pennsylvania, with high electricity prices at the time. The purpose of these reforms was to allow for greater reliance on market forces to determine the mix of resources and the allocation of risk between investors and consumers, and to allow customers to exercise greater choice in satisfying their own energy requirements. Typically, these states implemented these reforms through a process that included a transition period before moving to more full-fledged competition. Some of those states still find themselves in that transition, as do parts of Pennsylvania. The other two-thirds of the states retained the core structural elements of their traditional regulatory model, in which electric utilities typically own generation, transmission and distribution, with many costs and investments of the privately owned utilities subject to state rate regulation. Both types of states' electric industries operate – to a greater or lesser degree – within the context of national policy that embraces competition in wholesale power markets, with that competition enabled through a requirement for generation suppliers having non-discriminatory access to transmission facilities and interconnected markets.

Both types of states and regions – those that have taken a path relying on more competitive structures, and those that have remained on a path of traditionally regulated utility structures – will require investment to assure adequate electricity supplies in the future. A factor that likely would undermine the ability of electric companies in *either* part of the country to attract investment capital is uncertainty about the rules of the road going forward. Material uncertainty in the regulatory structure, in the investment recovery rules, and so forth, will raise the cost of doing business as compared to environments where there is a relatively stable regulatory framework in place.

Recently, many people have questioned whether the right road was taken in one state or another, and what reforms are now needed to bring things back on track. Some suggest a return to what they view as a more protective set of arrangements they associate with regulation. In many respects, this overlooks the fact that traditional regulation also has had its own notorious problems. Many scholars and industry experts have studied these issues, and most tend to conclude that we should remember that there were no "good old days" and that traditional regulation had significant (although different) problems of its own.[33]

In light of this, a useful foundation for constructive discussions in this industry is the notion that neither regulation nor competition is perfect. This provides a basis for a reality-based dialogue — one that gravitates towards finding improvements in industry approaches already in place in a particular region, rather than attempts to throw out the current industry model in hopes that the alternative will be something better. This will support the kind of stable regulatory environment that investors find attractive.

This point is particularly important, given that the electric industry is inherently technology-based and capital-intensive investment (whether baseload generation, or transmission, or renewables, or even many energy efficiency installations). This industry has always operated through complex, enormously technical, engineered systems of generators, transmission lines, distribution systems, and a variety of control technologies.

Given the need to attract prudent investment in new electric generation and demand management technologies, it seems as important to create an environment of regulatory stability. New, innovative types of electric resources and technologies are necessary for assuring that the next vintage of long-lived power plant investments are clean and efficient, so that (among other things) the carbon emissions from the electric industry begin to decline in ways that mitigate emissions contributing to climate change. Technology is also required — and already available — for enhanced, more reliable and more secure transmission investments, allowing for a more robust electric system that positions the U.S. for the needs of the 21st century. Additionally, many of the technologies for enabling customers to better manage and make efficient use of electricity are already known, but have only been deployed in very limited contexts. Achieving the economic, reliability and environmental benefits of technology adoption is critically important for the country, but depends upon keeping an eye of improving, rather than making more chaotic, the rules of the road.

2. POLICY MAKERS SHOULD HEED THE LESSONS LEARNED IN OTHER STATES WHEN RATE FREEZES WERE IMPOSED AT LEVELS OUT OF LINE WITH FUNDAMENTAL MARKET CONDITIONS.

When most states restructured their industries a decade ago, they adopted a package of reforms designed to make the electric industry more efficient, to provide consumers with prices disciplined by market forces, to cause electric suppliers to internalize the risks of certain types of investment decisions, and to transition to a fully competitive retail and wholesale power market. Many of these states, like Pennsylvania, adopted a package that also included elements (such as rate caps to be in place over a temporary and predetermined time frame) designed for fairness, efficiency and "orderly transition" goals.[34]

At the time these packages of reforms were implemented, most states ensured that the pieces were in place so that customers would be assured the possibility of continuing to take service at a regulated (and in many cases, frozen or capped) rate for a defined period of time. In most states, this meant that the electric utility would have continuing obligations to provide generation service to customers even though it did not have supplies; therefore, it would need to arrange with a third-party to provide it with wholesale supply for this purpose. The third-party competitive supplier would know, at the time it signed up for this commitment, the terms and conditions under which it would provide supply. Typically, there was a clear end date of the supply contract, often timed with the end of the transition period's rate freeze. This provided the sort of financially viable, symmetrical contractual arrangement that would (a) assure customers with power at fixed prices, (b) ensure that that power would be provided by a willing seller at the terms and conditions established at the time the contract was signed, and (c) keep the utility, in its role as the "agent" for the retail basic service customers, in a financially neutral fashion, neither earning a return on this function nor taking financial risk. In essence, this is the type of workable arrangement in place for each of Pennsylvania's utilities that have been providing fixed price basic service to consumers during each utility's transition period.

A notorious example of a state that drastically erred in extending its rate caps is California. When California restructured its electric industry in the mid-1990s, the rules required the utilities to provide basic service to consumers at a fixed (capped) rate, set in motion the divestiture of utilities' power plants, and required the utilities to buy all of their daily power supply needs for their basic service customers in the marketplace. This arrangement collapsed in 2000/2001, when prices in wholesale markets began to diverge – first somewhat, and then to a dramatic degree – from the capped retail prices. The situation was ultimately – and fundamentally – not sustainable. As the spread between capped rates to consumers and wholesale power supply prices widened over time, utilities had to spend more to buy power from third parties than the utility could ever hope to collect from consumers. Eventually, California's investor-owned utilities lost their credit-worthiness, one (PG&E) declared bankruptcy and another (SoCal Edison) barely avoided doing so. As a result, the State of California stepped in to contract for supplies under emergency conditions, hardly an opportune time to be contracting for power. While California's experience was clouded by a number of other well-chronicled problems, one central issue that led to financial problems for nearly everyone was the state's policy that required, in essence, that utilities sell power for their retail basic-service customers at capped rates even as those utilities had to purchase power at higher market-based rates. The political, financial, and economic fallout of the cascading set of problems is well known to industry and lay observers, alike.

California's experience provides an important lesson for any state considering whether to impose or extend a rate cap when market conditions have significantly diverged from the price levels at which the rate freeze was (or is) set. It is a reckless strategy, entirely inconsistent with either the competitive market model for the electric industry or the regulated, cost-of-service model. The latter, more traditional approach is one in which the utility is obligated to provide service to consumers and to be compensated for doing so at just and reasonable rates; long-standing regulatory practice as well as court decisions support the premise that the utility's rates are just and reasonable when they provide the opportunity for the utility to recover its costs and earn a fair return on its investment. Imposing rate freezes at levels out of line with market conditions violates that balance between the utility's obligation (to provide service) and its rights (to be permitted to charge rates that allow it the opportunity to earn a fair return).

Today, extending rate caps at current levels (i.e., at levels well below current market prices) at a time when there is no expectation that market prices will actually go down in the future is surely a formula for disaster. This strategy should be understood as genuinely being "too good to be true." And therefore not viable. It will be damaging to a utility's financial health. And it is also likely to impede the development of retail markets, keeping customers from seeing and understanding the true cost of electricity in today's conditions, and inappropriately dampening demand response.

A decade ago, in adopting the Electric Competition Act, Pennsylvania's leaders understood the importance of ensuring a financially viable utility industry as part of the move toward competition markets. The Act included several provisions to protect against situations where the utility's financial foundation would be materially undermined.[35]

Policy makers in the Commonwealth today should heed the lessons learned in other regions' power markets when they consider imposing rate freezes out of line with market conditions. California's experience warns that keeping rate freezes at that time would impose dire financial consequences for those companies, send the signals to investors that are opposite to the investment-friendly climate that the state is hoping for, and will raise costs to consumers in the long run. After Pennsylvania's rate freezes expire in upcoming years, those companies cannot avoid obtaining power at current market prices. They no longer own the generation needed to supply the needs of their customers and even if they did, they could not avoid paying the current market price for fuel to generate electricity. And it is that fuel price that is the primary driver for increased electric prices.

3. OTHER AVAILABLE TOOLS, NOT RATE CAPS, CAN HELP ELECTRICITY CONSUMERS MANAGE THEIR ELECTRIC BUDGETS IN THE FACE OF HIGHER ELECTRICITY PRICES.

As many states have emerged at the end of their transition periods, some have navigated the path more smoothly than others. The experience in other states provides some useful guidance about what to do – and what to avoid – as Pennsylvania transitions to providing consumers with prices reflecting today's market realities. It will be critical to adopt new regulatory policies that build on and fit with the core features of the path towards competition that Pennsylvania's electric industry has taken over the past decade. Then, shaping those policy refinements so as to provide electricity customers with the kind of information, service and product options, and other types of assistance they need will help Pennsylvanians better manage their energy needs and control their electricity expenditures. Policies consistent with this objective involve allowing more vibrant retail choice to develop, adopting incentives for advanced metering, offering customers better pricing options, services and technology packages to enable them to better manage demand, and programs to assist low-income customers.

Best practices for emerging from the transition period's capped rates. Best practices include: strong consumer education in advance of the shift from capped rates to market-based rates; information about the changes that have occurred in external fuel markets and other trends that lead to higher prices; new rounds of information to inform consumers about the types of products and services available from alternative suppliers; targeted assistance to low-income consumers; provision of an array of energy-efficiency and demand-side measures to consumers, timed before or in conjunction with the move to market-based rates; adoption of advanced metering devices with options for all consumers to buy electricity under time-of-use prices; use of well-designed and implemented competitive procurements for basic generation service to be offered by the local utility (more on this below); phasing in of market-based rates over a time certain. States might also include some use of a form of "shadow pricing" of prices that vary over time, in advance of actually moving to market-based rates.

Things to avoid from experiences of other regions. If there are too many changes going into effect at once, consumers may become overloaded. For example, Illinois learned this lesson when one utility re-allocated costs among customer classes as part of new retail rate designs and put these new rates into effect simultaneously with the move toward market-based generation rates. This type of action can lead to larger-than-expected rate shock for certain customers, even when the overall impact of market-based rates has been well-explained and understood.[36] The timing and manner of phasing new market-based rates into effect might be informed by information available on forward market conditions. The more it appears that forward markets are at a particularly high point in normal price cycles across the year (or due to particular unusual events in world fuel markets), the more the state might want to phase-in the full impacts of market prices. This was an important lesson to take away from Maryland's experience, when it went out to markets to procure power supplies just after natural-gas prices soared following the Hurricanes of 2005. The phasing-in of rates is important both in the short run and the long run. In the short run, this helps smooth the effect on electricity consumers' budgets. In the long run, it enables customers to begin to see the true cost to provide them with electricity. Consumers will be better able to manage their own electricity bills if more light is shed on electricity realities.

Other strategies to help consumers emerge from transition periods. There are ways to assist consumers with managing their electric budgets through innovative policies and technology, much of which already exist but await the decisions of policy makers to promote them more aggressively. For example, adoption of higher efficiency standards for consumer appliances sold in the state makes more sense as electricity prices rise and the value of saving energy increases. Advanced building codes for more efficient building design and the adoption of efficient heating and cooling systems (such as distributed generation technologies) will be more attractive for consumers seeking to manage their energy bills. Regulatory policies promoting more aggressive energy efficiency and other demand-side programs are a way for consumers to better manage their power usage and electricity bills. There is a growing literature on best practices in regulatory policies and financial incentives to create the right foundations for adoption of cost-effective energy efficiency and load-management measures that provide savings to the consumers who install them but also for the system as a whole.

Also, there are advanced meters and other "smart" equipment that allow customers to see how much it costs to supply power to different appliances at different times of day. There are devices and service providers offering relatively seamless ways to better manage customers' usage patterns — such as through cycling many customers' air conditioners in ways that reduces a significant amount of power requirements without reducing comfort or convenience; those who sign up can receive a check for their savings. Large sophisticated users of electricity are already adopting such ways to manage electricity and save money.[37] But small users who are shielded from knowledge of the prices to supply power at different times of day have weak (if any) motivation to pursue such devices. The technology, therefore, may exist to keep them informed, but there is insufficient motivation to adopt it.

Enabling this kind of customer response to market conditions is critical to the performance of markets themselves, as well as to the ability of consumers to manage their energy use and electricity bills. The value of harnessing price signals to help supply resources to the system and to discipline prices has been seen in recent years in many RTO-administered wholesale markets. It is no accident that these programs have moved quite aggressively in these markets in recent years, since the transparency of hourly wholesale prices has enabled the possibility of customers seeing electricity prices and making decisions for themselves about whether they prefer to curtail their usage when prices hit a particular threshold.

4. WELL-DESIGNED COMPETITIVE POWER MARKET POLICIES AND RULES MATTERFOR KEEPING PRICES TO CONSUMERS AS LOW AS POSSIBLE.

While today's electricity markets are neither perfect nor fundamentally flawed,[38] there are still important elements of market design that would improve their performance, both at the retail and wholesale levels.

In regions with organized wholesale markets, for example, the suggested improvements[39] differ by region, but there are some common themes. These include: implementing clear capacity obligations and forward capacity markets to ensure that efficient and adequate investment can take place; further refining and deepening the demand-response side of the market; improving long-term regional transmission planning; allowing long-term financial transmission rights; establishing more precise and consistent definitions of what constitutes workably competitive markets and best practices for monitoring and mitigating markets; improving various "seams" issues at the borders of markets; allowing long-term contracting in ways that align well with organized market design; and better managing the costs to administer wholesale markets. FERC and many states have had a number of these issues on their agendas for some time and have made great strides towards achieving reasonable federal policies. Pennsylvania should continue to support these efforts.

Important refinements in state policies are needed to keep power supply costs as low as possible. Improving price signals to retail consumers so that many fewer see average prices in all hours, will help discipline prices in wholesale markets. So will well-designed and implemented competitive power procurement processes, enabling the local utility to obtain power supplies for those retail customers electing to remain on basic service. As Pennsylvania's rate caps end for all utilities in the future, they will need to arrange for new supply for basic service customers for the post-transition periods. Using competitive processes to provide the lowest-cost supplies means that third parties take on market risk rather than having the utility (and by extension, the consumer) do so. In states with retail choice where the local distribution company focuses of "delivering" power and no longer carries out generation functions, the utility no longer has comparative advantages in power markets. Here, the utility provides a basic product – "full-requirements generation service" – and serve as the conduit for these customers in the competitive market place. In this conduit role, the utility calls upon third-party suppliers to provide all of the necessary components of providing supply to customers: energy, capacity, ancillary and other services (such as meeting Alternative Energy Service requirements) at all times and at all levels of customer demand over the course of a day or a season. The utility can make good use of competitive markets to find lowest-cost supplies of "full requirements" power to meet the needs of basic generation service customers; it can do so by defining the product it purchases from competitors, rather than choosing the individual components of a particular portfolio of generation resources used to provide the product. It is the experienced participants in wholesale markets who take on the tasks of developing a portfolio of resources, making physical arrangements to lock-in certain supply, arranging for transmission of the supplies, making financial arrangements to hedge their financial and price risk, and offering to sell at a fixed price offer in competition with other suppliers.

One of the advantages of competition in the procurement of such "all-requirements service" is that it taps into the abilities and skills of different players to develop different and innovative strategies to meet and adapt to power supply conditions as they change in the future. This provides a diversity advantage to consumers. It passes risk from consumers and the utility that is serving as their supply conduit over to the third party supplies.

Experience in other states' procurements for basic generation service shows that it is possible to design and implement competitive processes so as to hedge price risk. This can be done through staggered procurements that purchase "slices" (or tranches) of supply for different future time periods (e.g., some for six-month contracts, others for longer periods) so as to mitigate the effects of shorter- and longer-term variations in prices. The staggering of procurements and the differing terms of the "slices" of supply thus provide a portfolio that can buffer the effects of otherwise more volatile prices. Additionally, the terms of these procurements can reflect solicitations for suppliers to provide any number of "preferred attributes" reflecting policy preferences of a state or a utility. For example, the procurements could require bidders to provide offers with a percentage of supplies from resources with particular carbon content. The suppliers thus arrange for a package of supplies that integrate different resources with different price, risk, and other attributes needed to meet the needs of basic generation service customers.

In this model, regulators (or other policy makers) specify the types of inputs needed (e.g., whether to require procurement of alternative energy resources) and market participants offer supplies through competitive processes that determine lowest-cost providers of resource portfolios. This contrasts well with alternatives in which the regulator requires the utility to procure particular types of resources (e.g., a procurement of baseload supply), to determine which particular resource(s) to contract with, to determine how that resource fits into an overall portfolio, and in so doing, looks to the regulator to allow it to recover the cost – and risks – of its portfolio management function from consumers. Thus, well-designed and implemented competitive power procurements offer a prudent and efficient means to provide this wholesale supply in ways that provide important benefits to consumers.

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ENDNOTES

[1] Data reflect prices as the end of 2006 (2006 data from EIA, Form 876 data), In 1996, the 19 states (including DC) with above-average electricity rates were (in order, from highest to lowest): Hawaii, New Hampshire, New York, Connecticut, New Jersey, Rhode Island, Alaska, Massachusetts, Vermont, California, Maine, Pennsylvania, Illinois, Arizona, DC, Florida, Michigan, Maryland, and Delaware. In 2006, the higher-than-average-priced states included all of those states (except Pennsylvania, Illinois, Arizona, and Michigan), as well as Texas and Nevada. Note that two high-priced states in 1996 and that restructured their electric industries after then were Pennsylvania and Illinois; both of these were still under rate caps at the end of 2006. All of the high-priced states except Hawaii and Alaska, Florida, and Delaware restructured their electric industries during the past decade.

[2] These percentages are calculated as the ratio of the average price in restructured states to the average electricity price in non-restructured states. Restructured states were considered to be: Arizona, Connecticut, District of Columbia, Illinois, Maryland, Maine, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Data are from EIA, Form 876 data. This trend has also been observed in the research carried out by Howard Axelrod, David DeRamus and Collin Cain and published in "The Fallacy of High Prices," *Public Utilities Fortnightly* (November 2006), page 59.

[3] Many observers have commented on the fact that states adopted a complex packages of policies when they adopted as part of the "restructuring" package, with some of these policies – such as multi-year retail rate freezes established at levels below prevailing prices in markets – inhibiting the ability of competitive retail markets to develop over time. On the other hand, such policies were part of the political bargains made to assure decision makers that there would be benefits for all consumers associated with adoption of policies to restructure the industry. See, for example, Ashley Brown, "Retail Procurement: Default Service vs. Monopoly Service Considerations," Presentation to Harvard Electricity Policy Group, October 5, 2007. Furthermore, it is not hard to overstate the inherent difficulty that exists in studying issues relating to the benefits and costs of "restructuring." Any attempts to assess empirically the impact of restructuring on consumer electricity rates must address a number of issues that complicate such an analysis. "The electric industry" varies for electric utilities within states, across states within regions, and even customer classes within individual utilities. Some states started restructuring under conditions of surplus capacity; others did just the opposite. Some had short-lived rate freezes; other still have them in place. Some allowed for retail customer choice for several years, and then switched gears. Some allow pass-through of fuel costs and expenses on a quarterly basis; others allow such costs to be recovered only if there are extraordinary increases. Some have long-term fuel contracts supporting a significant portion of fuel supply; others have contracts whose prices are indexed continuously to changing prices. Some RTOs have experienced several phases of market design since they began operation; others have just recently started to operate their markets. Even with a single RTO, the changes in market rules over time have created different types and degrees of incentives.

[4] By comparison, under traditional regulation utilities typically do not share in any of the financial gains from improved operating efficiencies. Under cost-of-service regulation, utilities generally recover their operating expenses but are not allowed to share in the savings they might create by increasing operating efficiency to reduce fuel costs or reducing other components of costs. While utilities might be able to share in some savings under certain circumstances (e.g., incentive regulation or due to lags between regulatory proceedings), the fact that savings are shared and often transitory create only partial incentives for utilities to undertake actions to improve plant productivity. Incentive regulation, which allows regulated utilities to share in the savings produced when plants exceed pre-determined performance benchmarks, creates similar incentives to those created by plant divestment. Lags between regulatory proceedings may allow regulated utilities to profit from cost savings until they are incorporated into rates in future periods.) One of the techniques used in many states to enhance such incentives for competition was divestiture of power plants, which in some cases allowed for firms to specialize in the operation of particular types of facilities (such as nuclear plant operations).

[5] Bushnell and Wolfram (2005).

[6] Global Energy Decisions (2005); Barmack, Kahn, and Tierney (2006). *See*, also, Cain and Lesser (2007), who found a 5-percent improvement in nuclear output, with a total efficiency benefit in PJM East's region of approximately $450 million in annual savings.

[7] Fabrizio, Rose and Wolfram (2006). *See*, also, Shanefelter (2006). For example, one study estimated improvements in fossil-fuel plant efficiency of roughly 2 percent, while another study found reductions in labor and operations costs of 3 to 5 percent. (Bushnell and Wolfram (2006) estimate approximately a 2 percent improvement in plant heat rates, which Wolfram (2003) estimates would generate savings of roughly $3.5 billion annually. Fabrizio, Rose and Wolfram (2006) estimate a 3 to 5 percent reduction in labor and operations costs, which, based on estimates provided by Wolfram (2003), would produce savings of at least $1 billion annually.) Improvements in the operation of nuclear facilities — where availability and output are estimated to have increased by 10 percent — appear to be largely the result of such consolidation. Although these improvements may not appear dramatic, when aggregated across all facilities, the combined annual savings could be in the billions of dollars.

[8] For example, Tierney and Kahn (2007) estimate the savings from increased plant availability in addition along with savings from other elements of restructuring, such as the consolidation of the multiple geographic areas that had previously used for economic plant dispatch.

[9] Restructuring has facilitated geographic consolidation in a number of ways. One is through the integration of dispatch (or, "unit commitment") decisions that had previously been made within individual sub-regions, such the integration of New York Power Pool sub-regions into the New York ISO. Geographic consolidation also includes integration of regions that were previously in separate RTO/ISOs or dispatch zones, such as the formation of PJM and the recent integration of American Electric Power, Commonwealth Edison, and Dayton Power and Light. One study of geographic consolidation in New York which also examined the impact of reduced outage rates for nuclear and fossil fuel units, found benefits of between $100 and $200 million per year, which is roughly 5 percent of the system-wide production and fixed operation and maintenance costs. Tierney and Kahn (2007).

[10] Another study of the benefits of the recent expansion of PJM to include the three Midwest utilities (AEP, ComEd, and DPL) found annual benefits of about $70 million in PJM and about $85 million when including regions outside of PJM. The $85 million annual savings reflects savings across the entire Eastern Interconnect, which spans the majority of the eastern and mid-west states. Global Economic Decisions (2005).

[11] In New England, for example, which has studied this issue directly, the region increased its power plant capacity by more than 40 percent (i.e., by nearly 9,800 MW) over the period from 1999 through 2005, with corresponding improvements in heat rates (with lower heat rate reflecting less fuel used to produce power) and overall emissions of carbon dioxide. Source: ISO-NE, Capacity Energy Loads and Transmission Reports ("CELT" Reports) for each year from 1999 through 2006. Capacity data in the table in SECTION I - Summaries Summer - NEPOOL and Total New England August Capabilities and Summer Peak Load Forecast (MW).

[12] http://www.pjm.com/contributions/news-releases/2007/20080810-demand-response-record.pdf

[13] See, for example, the November 2005 letter from seven companies (including Federated Department Stores, WalMart, 7-Eleven, and JC Penny) representing nearly 14,000 facilities and over $2 billion in annual electricity costs as commercial consumers of electricity. http://www.competecoalition.com/1115comments.pdf

[1414] The U.S. Electric Energy Market Competition Task Force's Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy (April 2007) provides a good summary of the difficulties experienced in many "retail choice" states in implementing workable competitive markets for small electricity customers.

[15] For example, an increasing percentage of retail customers in the service territories of Duquesne Light and Penn Power (both of whose rate caps have expired) are now being served by an alternative supplier. In Duquesne Light's service territory as of July 2007, 17% of residential customers (representing 16% of residential load), 17% of commercial customers (representing 50% of commercial load), and 44% of industrial customers (representing 88% of industrial load) were served by an alternative supplier for generation service. In Penn Power's area, 8% of residential customers (7% of residential load), 9% of commercial customers (50% of commercial load), and 63% of industrial customers (98% of industrial load) buy power from an alternative supplier. By contrast, companies whose rate caps are still in place have far fewer customers (or customer load) served by competitive suppliers: 0% of PPL's load, 1.5% of MetEd/Penelec's and 2.6% of PECO. http://www.oca.state.pa.us/Industry/Electric/elecstats/stat0707.pdf

[16] EIA, http://www.eia.doe.gov/cneaf/electricity/epa/figes1.html .

[17] EIA, Coal prices delivered to the power sector. Delivered Price for 1990-2004 from EIA State Data Tables, United States Table 6; for 2005-2006 from June 2007 Electric Power Monthly, Table 4.1.

[18] The strong relationship between changes in fossil fuel prices and changes in electricity prices is explained in more detail in a recent paper I authored, "Decoding Developments in Today's Electric Industry — Ten Points in the Prism," October 2007, prepared at the request of the Electric Power Supply Association. For convenience, I paraphrase footnote 5 from that report: In recent years, many analysts and scholars have studied the relationship between fossil fuel prices and electricity prices. For example, analyzing several decades of annual price data for natural gas and electricity, MIT's Paul Joskow found that there is a close historical relationship between fuel costs and residential and industrial electricity prices. *See*, Joskow (2006). Young Yoo and Bill Meroney from the staff of the Federal Energy Regulatory Commission found relatively strong explanations for electricity prices increases based on changes in natural gas prices. (Yoo and Meroney (2005).) Ken Rose (2007) observes that natural gas prices have played a role in explaining electricity price changes, along with other important factors including the level of customer load and the existence of different generating technologies (with different power production efficiencies). Greg Basheda et. al. (The Brattle Group), also find that *"Fuel and Purchased Power Cost Increases Have Been Enormous and Are the Largest Cause of Recent Electric Cost Increases.* On an industry-wide basis, our analysis finds that fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the last five years. The increases in the cost of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source." (Basheda et. al., page 2.)"

[19] 26 of the 30 states with electricity prices below the national average are in regions that produce a significant portion of their power from coal-fired power plants. In most if not all cases, these coal-fired power plants were constructed prior to restructuring.

[20] Peak demand increased by 12% over this period. An actual increase of 65,529 MW occurred from 680,941 MW (in 2000) to 746,470 MW (in 2005). Peak demand in 2007 was expected to be approximately, 760,840 MW in the U.S. Thus, an increase of approximately 80,000 MW was expected from 2000 through 2007. Texas' peak demand in the summer of 2006 was over 62,339 MW. Sources: EIA, Electric Power Annual (2006), Table ES1; North American Electricity Reliability Council, Long-Term Reliability Assessment, 2007, Table 32, ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2007.pdf, and NERC, "2007 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2007), page 11.

[21] "One large power plant a week" is based on: Actual net additions of capacity in the U.S. from the end of calendar year 1999 (i.e., the start of 2000) to August 2007 was approximately 210,480 MW. Dividing 210,480 MW by 392 weeks is 536 MW per week, equivalent to a medium-to-large power plant. EIA, Electric Power Annual (2006), Table 2.1 for end of year 1999 (785,927 MW), For capacity in August 2007 (996,410 MW): EIA, Electric Power Monthly, October 2007, Table ES3. New and Planned U.S. Electric Generating Units by Operating Company, Plant and Month, 2007 – 2008. http://www.eia.doe.gov/cneaf/electricity/epm/epmxlfilees3.xls

[22] Actual investment costs are not publicly available. This rough calculation is based on: capital costs of $550/kW for combined cycle power plants, and $325/kW for combustion turbine power plants (these two technologies accounted for most of the power plant capacity added during calendar years 2000-2005. These capital cost estimates were from RDI's Outlook for Power in North America 1999 Annual Addition (2000)). The calculation assumed that 2/3rd of the capacity added was in combined cycles, and the rest was combustion turbines. (More recent estimates of capacity costs are much higher. For example, 2001 estimates of capital costs were as follows: $616/kW to $800/kW for combined cycles, and CT (2001) of $400/kW to $600/kW for combustion turbines (from Barmack, Kahn, Tierney). A recent estimate of capital costs in 2007 is $800/kW to $1000/kW for combined cycles, and $500/kW to $700/kW (from ISO-NE Scenario Planning Initiative). Sources: EIA, Electric Power Annual 2006, Table ESI; RDI - Outlook for Power in North America - 1999 Annual Edition; Barmack, Kahn, Tierney (2006); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/apr302007/assumptions.pdf.

[23] Smith, Rebecca. "Court Decisions May Aid Some Utility Profits in Long Term," The Wall Street Journal Online. April 3, 2007. Available at: http://online.wsj.com/article/SB117556293661557706.html?mod=US-Business-News. Accessed August 24, 2007.

[24] Utilities' investments levels were $14.1 billion in 2000, and $15.8 billion in 2003. These figures are for shareholder-owned electric utilities. Edison Electric Institute, http://www.eei.org/industry_issues/energy_ infrastructure/transmission/Transmission-Investment-Expenditures.pdf (accessed July 28, 2007).

[25] NERC, "2006 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2006), page 15. This reflects additions of power lines at 230 kV and higher voltage levels, based on circuit miles added.

[26] EIA, Annual Energy Outlook 2007, page 36.

[27] The U.S. government has recently estimated that average "residential electricity prices are projected to increase by 2.5 percent in 2007 and by a slightly lower rate of 2.0 percent in 2008, slightly lower than the rate of inflation." EIA, Short Term Energy Outlook – September 2007, page 5. These projections are tied in large part to expected prices for fossil fuel prices, which are expected to remain high in the near term or longer term EIA, Annual Energy Outlook 2007, pages 4-6.

[28] EIA's Annual Energy Outlook (2007) "assumes that, for the purposes of long-term planning in the energy industries, costs will revert to the stable or slightly declining trend of the past 30 years." (page 36). Further, a "total of 258 gigawatts of new capacity is expected between 2006 and 2030, representing a total investment of approximately $412 billion (2005 dollars). If construction costs were 5 to 10 percent higher than assumed in the reference case, the total investment over the period could increase by $21 billion to $41 billion." EIA, Annual Energy Outlook 2007, page 41.

[29] "All told, investment in the transmission system is projected to add more than 7,122 miles of new transmission through 2009, and nearly 12,484 miles added during the 2005-2014 time period….Averaging $14 billion per year over the next 10 years, expected distribution investment is almost triple the size of projected transmission spending." Edison Electric Institute, "New Investments for Transmission and Distribution Systems Are Needed," September 2006.

[30] These are estimates of annual costs to comply with the Clean Air Interstate Rule, the Clean Air Mercury Rule, and the Clean Air Visibility Rule, parts of which begin to go into effect in 2010 with several compliance phases in the subsequent years. These annual costs compare to projected health benefits of approximately $63 to $72 billion in 2010 and $91 to $106 billion in 2015. (EPA, October 2005), http://www.epa.gov/airmarkets/ progsregs/cair/docs/cair_ camr_cavr.pdf, page 30.

[31] EIA, International Energy Annual, 2005, Table H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels, 1980-2005; EIA, Emissions of Greenhouse Gases In the U.S.2004, December 2005.

[32] Per-capita consumption of electricity among Americans increased by 13 percent from 1990 to 2003 (the most recent data available). (13242.8 kwh per person per year in 2003, as compared to 11687.2 kwh per person in 1990). Source: Basheda et. al., "Why are Electricity Prices Increasing?" 2007, Appendix A.

[33] See, for example, the recent paper by Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007). For my own particular views on this issue, see the National Regulatory Research Institute's ("NRRI") Journal of Applied Regulation, NRRI 30th Anniversary Edition 19976-2006, Volume 4, December 2006 (article on pages 45-47). See also, the separate comments of Linda G. Stuntz, John Rowe/Elizabeth Moler, presented to the FERC Conference on Competition in Wholesale Markets, Docket No. AD07-7-000, February 27, 2007.

[34] See for example Pennsylvania Electricity Competition Act, § 2802. Declaration of policy. http://www.puc.state.pa .us/ electric/ pdf/HB1509P4282.pdf

[35] Among the understandings that were part of the Electric Competition Act were that utilities ought to have the opportunity to earn a fair rate of return. Electricity Generation Customer Choice and Competition Act § 2804. Section 4.III. "...(C) The electric distribution utility is subject to significant increases in the rates of federal or state taxes or other significant changes in law or regulations that would not allow the utility to earn a fair rate of return. (d) The electric distribution utility is subject to significant increases in the unit rate of fuel for utility generation or the price of purchased power that are outside of the control of the utility and that would not allow the utility to earn a fair rate of return."

[36] This occurred for some customers in Ameren's service territory in Illinois.

[37] One demand-response provider company, Enernoc, indicated in 2006 that its customers for "total energy management" programs include a "who's who" of large industrial firms, commercial office buildings, educational, groceries, department stores, health care facilities, hospitality and other light industrial facilities. See http://www.ksg.harvard.edu/hepg/ Papers/Healy_Demand_Response_0306.pdf

[38] Saying that power markets are not perfect is different from saying that they are fundamentally flawed. As observed by Paul Joskow of MIT in February 2007, "The markets in the Northeast and Midwest organized around an LMP model and managed by an Independent System Operator (ISO) now work very well in almost all dimensions. These markets are extremely competitive under almost all contingencies. The wise use of independent market monitors and thoughtful market power mitigation mechanisms have largely mitigated potential market power problems when the few remaining contingencies arise. No market is textbook perfectly competitive and it is unreasonable to set that goal as a standard for wholesale electricity markets to meet." Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007).

[39] This list of suggestions is based on a variety of sources, including comments made by participants at FERC conferences on wholesale market performance. See, for example the comments of John Shelk of the Electric Power Supply Association (http://www.ferc.gov/EventCalendar/Files/20070228110115-Shelk,%20EPSA.pdf.), William Massey of Covington & Burling (http://www.ferc.gov/EventCalendar/Files/20070314144339-Massey,%20Covington%20&%20 Burling.pdf.), John Rowe and Elizabeth Moler of Exelon (http://www.ferc.gov/EventCalendar/Files/20070227090732-Moler%20and%20Rowe,%20Exelon.pdf), and Paul Joskow of MIT (http://www.ferc.gov/EventCalendar/Files/ 20070228090000-Joskow,%20MIT.pdf). (All accessed August 25, 2007).