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**Testimony Before the  
Senate Consumer Protection and Professional Licensure  
&  
Senate Environmental Resources and Energy Committees**

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**On**

**Energy Policy for Pennsylvania**

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## Overview of EPGA Remarks

Pennsylvania needs to continue to pursue the development of competitive retail and wholesale electricity markets. The marketplace is the best mechanism for eliciting the development of new generation while ensuring that consumers see the most efficient pricing of electricity.

We need to continue to support competitive generation as the primary supplier of Pennsylvania's electricity needs. This will allow for the most economic and efficient operation and investment in generation, and place the construction and operating risks squarely, and most appropriately, on the shareholders of generating companies rather than utility ratepayers.

Allowing electric distribution companies (EDCs) to get back into the business of building power plants will stifle competition. There would be little financial incentive for competitive generators to continue to invest in existing and new generation, and risk would be shifted back to electricity ratepayers. Instead, flexibility in the procurement of electricity (including spot, long-term, auctions, RFPs, etc.) by EDCs for their default service customers is a better way to ensure the desired portfolio diversity.

The uniform single price clearing market, used by PJM and every other organized wholesale electricity market in the U.S., provides a built-in mechanism to produce the lowest competitive prices. Indeed, the single price clearing market is the institution most responsible for the efficiencies and cost savings attributable to electric restructuring to date.

More than 96% of the average PJM wholesale price in 2006 was comprised of fuel (76%), environmental costs, other variable operating and maintenance expenses and congestion costs. Only 2.9% of the average wholesale price was contributed by generator markup.

Environmental policy at the federal, regional, and state level forces greater reliance on natural gas as a power plant fuel, while national, state, and local politics impede expansion of supply. These policy contradictions have contributed to debilitating rises in natural gas prices.

All public policy makers need to understand that ample gas supplies, electricity prices, electric reliability, and retaining manufacturing jobs are crucial issues that are inextricably linked.

Generation retirements in eastern PJM are expected to outpace new capacity additions, leading to greater use of natural gas and greater stress on the transmission system. Current and pending environmental initiatives can be expected to accelerate that trend.

We must be certain that proposed environmental regulations balance environmental and economic development needs. We must also make sure that regulations are supported by sound science.

Favoring certain long-term contracts in legislation shifts the burden of risk from the investor, where it belongs, back to the ratepayer, which is the situation that existed prior to electric restructuring.

The procurement provisions in the proposed amendments to the Competition Act codify the selection of winners and losers and interfere with the market by substituting a legislative preference for demand side and alternative energy resources, and creating a special test that some generation sources (such as coal and nuclear) must pass before they can be included in capacity plans. Given the time and resources required to plan and build adequate generation capacity, this provision could have serious adverse consequences for electric reliability and prices if government decisions turn out to be wrong.

If we are going to attract the investment and innovation on the scale needed to meet our energy security and environmental challenges, investors must be assured that the rules of the market will not be changed repeatedly or dramatically by legislation or regulation.

## Introduction

Madam Chairmen White and Boscola, Chairmen Tomlinson and Musto, distinguished members of the Senate Consumer Protection and Professional Licensure and Senate Environmental Resources and Energy Committees, good morning. My name is Doug Biden and I am President of the Electric Power Generation Association (EPGA). EPGA is a regional trade association of electric generating companies with headquarters in Harrisburg, Pennsylvania. Our member companies include:

AES Beaver Valley, LLC  
Allegheny Energy Supply  
Cogentrix Energy, Inc.  
Edison Mission Group  
Exelon Generation  
FirstEnergy Generation Corp  
Mirant Corporation  
PPL Generation, LLC  
Reliant Energy  
Sunbury Generation, LP  
UGI Development Company

These companies own and operate more than 122,000 megawatts (MW) of electric generating capacity in the United States. Approximately half of this capacity is located in Pennsylvania and surrounding states. Our comments today represent the views of EPGA as an association of generating companies, not necessarily the views of any particular member company with respect to any specific issue.

At the outset, EPGA would like to express its appreciation to both committees for the opportunity to present its views regarding energy policy for Pennsylvania and to provide comment on the bills implementing the Governor's proposed Energy Independence Strategy (EIS).

### Why did the General Assembly restructure the electric industry in 1996?

Because some provisions of the EIS, specifically the proposed changes to Title 66 – The Public Utility Code, amend portions of the Electricity Generation Customer Choice and Competition Act, Act 138 of 1996 (the Competition Act), it could be useful to recall and establish a common understanding of why the General Assembly decided by a substantial majority to restructure the electric industry.

The electric industry was restructured primarily because the past regulatory system had failed. The old system resulted in prices for some Pennsylvania consumers that were well above regional

and national averages. Utilities were not building power plants anymore after a wave of rate base disallowances. When generation was subject to state rate-of-return regulation, retail electricity consumers absorbed huge rate increases due to construction cost overruns and power plant operations that had no incentives to improve efficiency. Then there were the high costs associated with PURPA contracts when the state entered the era of government mandated resource planning. Many of the above market costs from these past regulatory eras became “stranded costs” when we restructured in 1996 and retail ratepayers are still paying for them today in many utility service territories and will continue to do so until the end of transition periods for each utility. Plainly, “the good old days” were not so good for consumers.

There were three main goals of electric restructuring:

1. Shift the financial risks of construction, operation and ownership of generation from captive ratepayers to investors, who are positioned to manage those risks effectively;
2. Provide market incentives for generation owners to build and operate plants more efficiently; and
3. Promote competition and innovation in retail markets.

#### How are we doing?

The shift of financial risk has clearly occurred. In Pennsylvania, ratepayers no longer bear the financial burden of excess capacity, construction cost overruns, and forced outages that plagued many utilities during the traditional regulated era. Just as importantly, competition has shifted the risks associated with the construction of the next generation of power plants away from consumers. These new plants will be required as demand for power grows and as older plants retire. In fact, over the past 10 years, more than 9,000 MW of new capacity has been built in Pennsylvania.

Tremendous improvements in power plant operating efficiency were expected and have been realized and documented in several economic studies. One study estimated that competition has saved electric customers in the Mid-Atlantic area between \$430 million and \$1.3 billion each year compared to what would have been paid under traditional regulation. Increases in output at baseload nuclear and coal plants, increases in plant availability rates, reductions in forced outage rates and optimized maintenance practices have all benefited consumers. The value of increased nuclear output alone to Pennsylvania consumers is estimated at \$122 million per year, and rising.

Regarding the third goal of restructuring, it is premature to gauge the effectiveness of the 1996 Competition Act in creating retail competition while rate caps still remain in place. Clearly these rate caps have stifled retail competition, as they do in all markets. The price caps have likewise restricted development of demand response and energy efficiency by directly subsidizing retail electricity consumption. However, there are no reasons why retail competition (and the beginning of effective demand response) will not occur in Pennsylvania once those rate caps expire and customers see market-based rates.

In fact, retail competition, especially for large customers, has flourished in utility jurisdictions once rate caps have been lifted.

In 1996, Pennsylvania rates were 15% above the national average. In 2006, average electricity prices in Pennsylvania were 2% below the national average, and 12% lower than consumers paid in 1996 (adjusted for inflation). Clearly, consumers have benefited greatly from retail price caps.

## What's driving electricity prices?

Now, policymakers are looking to the future (and to recent experiences in Maryland, Pike County Light and Power and some other utility jurisdictions) and are wondering what's going to happen when the price caps expire for most Pennsylvanians in 2010-2011?

We have seen, in other states and, to a certain extent in Pennsylvania, some counter-productive policy proposals, a recoiling from the market based in part on a lack of appreciation of the forces that are driving prices and how the market works, and in our view a tendency to reach for "solutions" that could make matters worse.

That's why we believe it is vitally important that your two committees, which play such a pivotal role in energy policy matters, fully understand what is driving electricity prices and how prices are determined in the competitive wholesale market.

Some would have you believe it is electric competition and market design that is causing electricity prices to rise. However, any fair and unbiased review of the facts will show that it is clearly the price of natural gas, oil, coal and even uranium that is primarily driving up electricity prices – not just in restructured states, but in every state across the country. And just as with the cost of gasoline at the pump, no one is able to fully shield the consumer from these cost pressures indefinitely.

As your committees know, EPGA's members sell the output from their power plants into the largest and one of the most competitive power markets in the world – PJM. The core of the PJM market (the spot market) is based upon a single price clearing concept. Generators offer quantities of electric power into the market at prices for which they are willing to sell. In such a market, the lowest cost power plants are dispatched first, and higher cost plants are dispatched in economic merit order until all demand is met. All generators receive the highest price bid that is needed to satisfy market demand. This is what is known as the "market clearing price." It is the price that must be paid to meet a given level of demand at any given time. This can best be explained with a simplified example. Suppose PJM needs 1,000 megawatts (MW) and has these 4 bids:

Generator A: 400 MW @ \$25/MWH  
Generator B: 400 MW @ \$30/MWH  
Generator C: 300 MW @ \$35/MWH  
Generator D: 200 MW @ \$40/MWH

In this case, PJM would choose the entire bids from Generators A and B, and 200 of the 300 MW bid from Generator C at \$35/MWH. This \$35 would be the market clearing price to be received by each of the 3 successful bidders A, B and C. Generator D would receive no energy revenues in this example. This type of market provides a powerful incentive for generators to minimize their operating costs because only the offers of the least-cost suppliers are selected.<sup>1</sup>

This uniform single price clearing market, used by PJM and every other organized wholesale electricity market in the U.S., provides a built-in mechanism to produce the lowest competitive prices. It encourages generators to offer their output at their variable marginal cost in the hope of maximizing the chances that their offer will be accepted. It forces generators to minimize their variable costs so

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<sup>1</sup> In addition to the spot market, much of PJM energy is transacted through longer term bilateral contracts between buyers and sellers. However, contract trades often reflect spot prices. Therefore, the incentives established in the spot market to minimize costs to assure that a generator's plant is chosen to run in economic merit order, help to influence favorably the price of bilateral trades.

that higher bids will set the clearing price, enabling them to recover their fixed costs and perhaps earn a profit.

Clearly, under the single price clearing market system, financial success depends on efficient operations. The lowest-cost, most efficient generators receive the greatest reward. As a result, the system encourages construction of efficient generation over time assuring long-term cost minimization.

Indeed, the single price clearing market is the institution most responsible for most of the efficiencies and cost savings attributable to electric restructuring to date. And EPGA believes that attacks on single price clearing markets, some of which have surfaced in hearings before your committees, misdirect policymakers from addressing the underlying energy market fundamentals and environmental issues that have driven electricity prices in recent years and will continue to do so for the foreseeable future.

This table shows the type of fuel used by the “marginal units” (the plants setting the market clearing price) in PJM over the last 3 years.

<b>Type of Fuel Used by Marginal Units in PJM</b>			
<b>Fuel Type</b>	<b>2004</b>	<b>2005</b>	<b>2006</b>
<b>Coal</b>	<b>60%</b>	<b>69%</b>	<b>70%</b>
<b>Misc.</b>	<b>0%</b>	<b>1%</b>	<b>1%</b>
<b>Natural Gas</b>	<b>32%</b>	<b>23%</b>	<b>25%</b>
<b>Nuclear</b>	<b>0%</b>	<b>0%</b>	<b>0%</b>
<b>Petroleum</b>	<b>9%</b>	<b>8%</b>	<b>4%</b>

You can see that coal set the market clearing price over 70% of the hours in 2006. This means that as a group, coal-fired plants had the opportunity to try to recover their fixed costs and to earn a profit in the remaining 30% of the time – when units burning natural gas or petroleum set the price. Natural gas plants set the price over 25% of the hours in 2006. So, taken together, coal and natural gas set the market clearing price in PJM over 95% of the hours in 2006. Obviously, these fuels have a pronounced effect on wholesale power prices.

The price of these two pivotal fuels has increased markedly in the PJM region in recent years as the following table demonstrates (prices in dollars per MBTU). Source—2006 PJM State of the Market Report.

	Natural Gas	Coal
<b>1999</b>	<b>2.62</b>	<b>1.62</b>
<b>2000</b>	<b>5.18</b>	<b>1.39</b>
<b>2001</b>	<b>4.52</b>	<b>2.14</b>
<b>2002</b>	<b>3.81</b>	<b>1.54</b>
<b>2003</b>	<b>6.45</b>	<b>1.76</b>
<b>2004</b>	<b>6.65</b>	<b>2.74</b>
<b>2005</b>	<b>9.73</b>	<b>2.88</b>
<b>2006</b>	<b>7.40</b>	<b>2.68</b>

Delivered natural gas prices increased almost four-fold between 1999 and 2005 before softening in 2006. Coal prices increased by 78% between 1999 and 2005, but also moderated somewhat in 2006. Despite these dramatic fuel price increases, the average price of electricity generated in the PJM market rose only 56% between 1999 and 2006. And the average price declined by almost 16% in 2006 to \$53.35 per megawatt-hour (MWH) - down from \$63.45/MWH in 2005 - despite record peak demand in PJM last year.

The table below shows the components of generation prices, prepared by the Market Monitor of PJM. You can see from this breakdown that more than 96% of the average wholesale price was comprised of fuel (76% - coal, gas, oil, uranium, wind), environmental costs (13% - NOx and SO2), other variable operating and maintenance expenses (5%) and congestion costs (2%).

### Components of Annual Load-Weighted Average LMP 2006

Element	Contribution to LMP	Percent
Coal	\$20.67	38.7%
Gas	\$17.23	32.3%
Oil	\$2.65	5.0%
Uranium	\$0.00	0.0%
Wind	\$0.01	0.0%
NOX	\$1.53	2.9%
SO2	\$5.39	10.1%
VOM	\$2.67	5.0%
Markup	\$1.54	2.9%
Constrained Off	\$1.06	2.0%
NA	\$0.59	1.1%
<b>TOTAL</b>	<b>\$53.34</b>	

Notably, only \$1.54 or 2.9% of the average wholesale price, was contributed by generator markup. We believe this is remarkably low for a capital-intensive industry that successfully met a record peak demand last year. In revealing this breakdown at a recent PJM meeting the Market Monitor remarked that these results are “very close to perfect competition.”

### Fuel Supply Issues

As generators, we have serious concerns about the adequacy of our natural gas supply over the next several years. Environmental policy at the federal, regional and state level forces ever greater reliance on cleaner burning natural gas as a power plant fuel while national, state and local politics impede expansion of supply. These policy contradictions have contributed to debilitating rises in natural gas prices. This increase in natural gas prices has been implicated in the loss of more than 3 million manufacturing jobs in the U.S. since 2000.

The gas supply and demand imbalance that became clear in 2005 did not begin or end with Hurricanes Katrina and Rita. Conventional domestic wells and imports from Canada are declining and we urgently need new sources of supply. Political leadership will be essential to open up the Outer Continental Shelf to exploration, 85% of which currently remains off limits, and to permit liquified natural gas facilities. All public policy makers need to understand that ample gas supplies, electricity prices, electric reliability, and retaining the manufacturing jobs we have left in this country are crucial issues that are inextricably linked.

### Environmental Issues

Environmental regulations impact not only generators' capital and operating costs, they also affect choice of fuels as well as unit retirements. Time will not permit a full discussion of the many environmental issues that could affect electricity prices. So I will limit my remarks to a brief overview of the more important issues that could affect prices over the near to mid-term.

In the Clean Air Interstate Rule (CAIR) and mercury regulations (both federal and state) the generation industry faces its greatest environmental challenge to date. Estimates of capital costs of CAIR alone have been as high as \$80 billion, with total annual costs in the range of \$15 billion. For Pennsylvania plants, we estimate CAIR capital costs at between \$4 and \$5 billion.

Phase I emission reduction deadlines for nitrogen oxides begins in 2009, and deadlines for sulfur dioxide and mercury occur in 2010. More stringent Phase II CAIR deadlines must be met in 2015 as well as the Phase II requirements for the Pennsylvania mercury rule.

EPA estimates 5,000 MW will retire because of CAIR and the federal Clean Air Mercury Rule in the eastern U.S. Consultant estimates are more than double that amount. PJM estimates that as much as 4,000 MW of coal-fired generation could be retired because of more stringent state mercury rules like Pennsylvania's.

Some PJM states are proposing their own carbon limits on power plants via the Regional Greenhouse Gas Initiative (RGGI). We have not yet seen the Rendell Administration's climate change initiative, but the Governor has said it will make Pennsylvania a leader on this issue.

The Northeast Ozone Transport Commission (OTC), of which Pennsylvania is a member, has adopted a memorandum of understanding to seek additional (beyond CAIR) NO<sub>x</sub> reductions from

generating units on “high electric demand days” (HEDD) to help address some East Coast areas that have chronic problems attaining the ground level ozone standard.

PJM predicts that generation retirements in the eastern part of the RTO are expected to outpace new capacity additions, leading to greater use of natural gas and greater stress on the transmission system. These environmental initiatives I’ve mentioned can be expected to accelerate that trend.

Because all of these new requirements will lead to higher prices for coal-fired electricity, and add to greater use of expensive natural gas as a power plant fuel (and an increase in the number of hours over which gas-fired plants set the market clearing price in the wholesale market), we must be certain, as a matter of energy and economic policy, that proposed environmental regulations balance environmental and economic development needs. We must also make sure that regulations are supported by sound science, as required by Senate Bill 752, introduced by Senator Erickson.

A discussion at last week’s hearing about power flowing into and through Pennsylvania from out of state, displacing Pennsylvania generation, underscores the importance of generator regulation that recognizes we are part of a large, intensely competitive regional market that extends from New Jersey to North Carolina to Illinois and includes more than 165,000 MW of generating capacity. Making Pennsylvania regulations, particularly air quality regulations, more stringent than federal regulations may appear like good public policy, but unless the other states in this multi-state region follow suit, all this policy succeeds in accomplishing is shifting generation and emissions (and jobs) to other states.

### Procurement of Electricity Supply

When it comes to issues regarding how electricity supply should be procured by default suppliers we generally agree with the counsel of PUC Chairman Holland that if the General Assembly feels it must provide guidance to the Commission in this area, it should “paint with a broad brush” and allow the Commission the flexibility it needs to adapt if and when the wholesale electricity market changes.

In the proposed amendments to Title 66 (Senate Bill 716), long-term contracts will be allowed only for new alternative energy sources and those sources approved by the PUC which are required for system reliability.

This limitation raises numerous issues:

- Electric Distribution Companies (EDCs) will not be able to enter long-term contracts for virtually all of the existing generation in Pennsylvania and in the PJM market.
- We question the appropriateness of state government picking winners and losers in the market.
- What criteria would they base these decisions on?
- Will the taxpayer or ratepayers be responsible for bad decisions? If not, who will be?

There appears to be a presumption that the cost of long-term contracts will be lower than market. In reality, long-term contracts can be higher or lower than shorter-term market results.

Legislation passed in Delaware last year required Delmarva Power & Light Co. to solicit bids for long-term contracts from power plants located in Delaware. Delmarva received proposals for a 20-

25 year contract from a new proposed 600 MW coal gasification plant, a 25-year contract from a 600 MW off-shore wind park, and a 10-year contract from a 180 MW natural gas facility.

According to Delmarva's analysis, all of the bids failed to deliver significant price stability benefits because of fuel price escalation clauses tied to inflation. The integrated gasification combined-cycle (IGCC) plant would cost Delmarva's customers \$5 billion more than power from the wholesale market. The wind offer would cost customers \$2 billion more. Although the gas plant offer was roughly equal to the cost of buying wholesale power, Delmarva concluded that the risks associated with fuel escalation clauses made it more cost-effective for customers to rely on the wholesale market.

One of the major benefits of electric restructuring was the shifting of financial risks associated with electric generation from ratepayers to investors. Favoring certain long-term contracts in legislation inevitably shifts the burden of risk from the investor, where it belongs, back to the ratepayer, which is the situation that existed prior to electric restructuring.

EPGA is also concerned about the procurement requirements in the proposed amendments to Title 66. That language requires that EDCs enter into contracts with energy efficiency and demand-side resources instead of electric generation facilities to meet any increases in energy usage and peak demand. If buying generation is necessary it must be purchased from alternative energy suppliers. EDCs can enter into contracts with non-alternative suppliers only upon a determination by the PUC that such generation resources are required to ensure reliability.

This procurement provision codifies the selection of winners and losers in the market, and launches state government into a level of resource planning in which it has no experience, never was engaged in during the past regulatory era, and introduces a practice that we believe is fundamentally inconsistent with the spirit and intent of the Competition Act.

Certainly, energy efficiency and demand resources must play an expanded role in meeting future energy needs, and they will as retail price caps expire and customers see market-based rates, the PUC implements the recommendations of its Demand Side Response Working Group, and PJM continues to aggressively expand both its emergency and economic demand response programs. But this proposed procurement provision appears designed to interfere with the market by inappropriately substituting a legislative preference for demand side and alternative energy resources, and creating a special test that some generation sources (such as coal and nuclear) must pass before they can be included in capacity plans.

EPGA believes it is unwise public policy for the state to dictate detailed decisions on how to procure power, or how electricity should be generated because the state is not equipped to make judgments on future prices of energy, environmental constraints, or wholesale market conditions, and the ratepayers/taxpayers should not be liable for the state's mistakes relating to power procurements. Given the time and resources required to plan and build adequate generation capacity, this provision could have serious adverse consequences for electric reliability and consumer prices if government decisions turn out to be wrong.

#### PEDA Should Not Become A State Energy Authority

EPGA is concerned about the language in Senate Bill 661 which appears to allow PEDA to become a state energy authority. Electric restructuring has produced widely documented improvements in generating unit operating performance which have greatly benefited consumers. We believe government entry into generation (or any other part of the competitive energy business) could

short-circuit competitive market-driven incentives to minimize costs and increase operating efficiency, and potentially discourage private investment.

#### Alternative Energy Portfolio Standards (AEPS)

Senate Bill 715 proposes to limit qualifying alternative energy resources in most of Pennsylvania to in-state sources or sources located in PJM. EPGA believes that compressing the AEPS market to only inside PJM will force development of alternative energy where it is not economic, significantly raising the cost of AEPS compliance.

For example, most of the potential for wind turbine development (the dominant tier 1 resource) is off-shore and in the mid-west plains. Trying to force the development of thousands of megawatts of wind capacity on to the ridge tops of Pennsylvania is unsound public policy. Although those may be among the best sites in PJM, they are not the most economic locations when considering a wider region that includes the Mid-west ISO Market, which the original legislative language allows. Alternative energy sources should be developed where they are most economic and where other market signals indicate they are needed, not according to artificial restrictions on market scope that are inconsistent with how wholesale electricity markets function.

#### Concluding Comments

As a nation, region and state, we face unprecedented challenges. We need to invest billions in new generation and environmental controls to meet a growing demand for electricity and increasingly stringent environmental standards. The Energy Information Administration estimates that we will need to invest over \$400 billion in new generation by 2030 if we are to ensure our energy security and address global climate change.

If we are going to attract the investment and innovation on the scale needed to meet our energy security and environmental challenges, investors must be assured that the rules of the market will not be changed repeatedly or dramatically by legislation or regulation.

You may recall that investment in new generating capacity came to a standstill in the early to mid 1990s when we were deciding whether or not to “deregulate” generation. Now, investors are again extremely wary of the multitude of state initiatives to “re-regulate,” turn back to government mandated resource planning, attacks on single-price clearing markets, etc. At this critical time Pennsylvania should not adopt energy policy provisions that will cause power plant investors to question their ability to recover their long-term investment in new capacity.

The rise in world energy prices over the last few years has rattled nerves and everyone is looking for answers. Generally, there is a stunned recognition that we are facing a very difficult situation that does not lend itself to quick fixes or short-term legislative solutions.

Whatever actions your committees decide to take with respect to electric energy policy we strongly urge you to consider that Pennsylvania is part of a larger regional market, and to coordinate state policy, as much as possible, with the rules and policies of the larger market in which we compete on a daily basis. Customers in Pennsylvania have gained real and important advantages from being able to access the regional competitive wholesale markets. Electric restructuring policy going forward needs to preserve and enhance the benefits of that regional participation. That means, among other things, that we need to continue to have state policies that fit with the practices of the regional markets, so that wholesale and retail suppliers in PJM can continue to offer service in Pennsylvania at the best prices possible. A policy of isolationism will not benefit Pennsylvania citizens.

It is important to recognize that electric generators, because they are one of the most capital-intensive industries in the nation, need a more stable and predictable environment in which investment decisions are made. We are hopeful that as more and more policymakers understand the link between generators' decisions, particularly regarding increased use of scarce natural gas, and the overall health of the economy, that they will come to understand the need for increased supply of that critical fuel, as well as the need for a more balanced, predictable and equitable approach to regulating power plant emissions going forward.

In closing, EPGA would like to say that while we have some serious concerns about some of the provisions of the Energy Independence Strategy bills, we appreciate the Administration's and the General Assembly's oft-stated commitments to supporting all Pennsylvania energy sources and continued fuel diversity in our energy mix. And we are committed to advancing policies which will do just that.

Thank you.