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PSEG
Services Corporation

November 17, 2008

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NOV 17 2008

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

VIA FEDEX

James J. McNulty, Secretary
Pennsylvania Public Utilities Commission
400 North St., Floor 2
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Current and Future Wholesale Electricity Markets
Docket No. M-2008-2066901

Dear Secretary McNulty:

Enclosed in the above captioned matter is the Reply Comments of PSEG Energy Resources & Trade LLC To the November 6, 2008 Public Hearing. Also enclosed is an electronic version of this filing on CD.

Should you have any questions on this, please contact me.

Very truly yours,

James E. Wrynn
Paralegal

Enclosure(s)

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NOV 17 2008

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Current And Future Wholesale Electricity Markets	:	**Docket No. M-2008-2066901**
	:	

REPLY COMMENTS
OF PSEG ENERGY RESOURCES & TRADE LLC
TO THE NOVEMBER 6, 2008 PUBLIC HEARING

PSEG Energy Resources & Trade LLC ("PSEG ERT) appreciates the opportunity to offer these comments in reply to the second hearing on Current and Future Wholesale Electricity Markets held on November 6, 2008. PSEG ER&T, an indirect subsidiary of PSEG Power LLC, sells power and energy and certain ancillary services at market-based rates in energy and capacity market regions administered by PJM Interconnection, L.L.C, New England Independent System Operator and the New York Independent System Operator. PSEG ER&T markets the capacity and production of PSEG Nuclear's and PSEG Fossil's generating stations, manages the commodity price risks and market risks related to generation, and provides gas supply services. PSEG ERT also is or has been a wholesale supplier of provider of last resort service in New Jersey, Pennsylvania, Maryland, Rhode Island and Connecticut.

I. INTRODUCTION

PSEG ERT recognizes the need for the Pennsylvania Public Utility Commission ("Commission") to review the operation of wholesale electricity market because of their impact on the Pennsylvania economy and quality of life of its citizens. The overwhelming evidence should however reassure the Commission that Pennsylvania is being well-served by the current market design and operation. PSEG ERT respectfully submits that Pennsylvania consumers have already received very significant benefits from competitive markets and that competitive markets clearly provide the best construct for supplying energy needs in the future.

The broad criticisms of competitive markets made at the November 6th hearing are unfounded. While enhancements can always be made, the basic design of the PJM markets is fundamentally sound. The discipline of competition will benefit consumers by providing incentives to suppliers to provide electricity at the lowest possible cost over the long run and in the most efficient manner. PJM has estimated the total value to consumers of efficiencies associated with PJM's operations to be up to $2.3 billion a year for the region.[1]

PSEG ERT's comments herein are limited to addressing four of the most prominent and troubling misstatements evident from the November 6, 2008 proceeding. These include the contentions that single clearing price markets result in overcharges to consumers, that the level of long-term contracts is insufficient and represents a failure of the markets, that markets are incompatible with achieving desired supply diversity and that regulated solutions would result in lower costs to consumers.

II. COMMUNICIATIONS

PSEG ERT requests that all communications concerning these reply comments be directed to the following persons:

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[1] *See* "PJM Efficiencies Offer Regional Savings," (available on PJM Interconnection, L.L.C. website at http://www.pjm.com/documents/downloads/presentations/pjm-value-proposition.pdf.)

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III. REPLY COMMENTS

1) The Single Clearing Price Design of PJM's Markets Is Grounded In Economic Theory and Results In Efficient Outcomes That Benefit Consumers.

Contrary to the certain contentions made at the November 6th conference, the design of PJM's energy and capacity markets are fundamentally sound and impose the discipline of competition on market participants. Consumers will benefit by receiving reliable electric service at the lowest available cost over the long run.

One particularly erroneous contention made at the November 6th conference was that the single clearing price model used in PJM energy and capacity markets over-compensates suppliers and imposes inappropriate costs on consumers. In fact, the single clearing price model is firmly grounded in economic theory and can be expected to yield the lowest costs to consumers over the long run. The pay-as-bid model endorsed by certain parties, at best, reflects a misunderstanding of how development decisions are made in efficient markets where energy margins and capacity payments are linked and, at worst, amounts to an attempt to take unfair advantage of market participants who reasonably expected to be appropriately compensated for undertaking the risks of development.

The single clearing price model pays all market participants at the singular price set by the marginal supplier. This provides the appropriate price signals to developers of generation and demand side projects regarding when to develop and what types of technology to employ. Developers will deploy capital when they perceive that prices will adequately compensate them including a reasonable return on investment over the life of the project. Paying some generators less than other generators based on the type of technology used or when the units are built will result in inefficiencies and higher costs over the long-run.

A single clearing price in energy and capacity markets, for example, provides the appropriate price signals for a developer to decide whether to construct a base-load plant (requiring higher energy margins) or a combustion turbine (which can be built based almost entirely on capacity revenues alone). If the developer knew that a base-load plant would receive lower energy revenues on the basis that its short-run energy production costs were lower than the short-term marginal costs of the combustion turbine plant, the plant would simply never get built. The infra-marginal margins are necessary to provide sufficient compensation to cover the base-load unit's cost of construction and a reasonable return.

Further, in short-term energy markets, a single marginal price provides the best price signal of which units to dispatch and provides market participants with incentives to bid their true marginal costs. In a single clearing price model, units with low short-run costs will bid as low as possible in order to maximize their run time thus minimizing the dispatch of higher cost units. Overall system production costs will be minimized. If a pay-as-bid model is employed, incentives resulting in lower production costs will be eliminated. In addition, studies show that in a pay-as-bid environment, bidders will attempt to "guess" the clearing price and bid at that level or engage in other strategic bidding behaviors. The result is likely to be higher clearing prices than would prevail under a single clearing price model.

Criticisms of the single clearing price design as an element of nodal "locational marginal pricing" ("LMP") in PJM are unfounded. These critics contend that the use of LMPs are somehow bad for consumers because they purportedly provide incentives for suppliers to act in ways that are inconsistent with normal market behaviors. One claim, for example, is that the use of LMPs undermines long-term contracting.

PSEG ERT has two responses. First, there is nothing inherently wrong with prices that cover short time intervals as these critics seem to suggest. Almost all commodities have short-term "spot" markets. The existence of such prices does not preclude longer term arrangements. In fact, spot price volatility provides incentives to enter into longer term arrangements in order to achieve a degree of price certainty and reduce volatility. In PJM, single clearing price LMPs are simply the result of technological advancements that enable PJM to post actual costs to deliver energy on a five-minute incremental basis.

Second, single clearing price LMPs provide very significant benefits. As noted above, in the short-term, they provide price signals that ensure the most efficient dispatch and scheduling of resources. Further, because of their locational properties, they are an effective tool to provide incentives for new generation and demand response in places where it is most needed. Similarly, single clearing price LMPs are also a very useful tool in terms of enabling loads to hedge electric costs. Indeed, it is precisely because we now have this transparent price signal that critics even can lodge their complaints that load in one area is being served at cheaper prices than another. Without LMPs, cost differentials for serving different regions are masked and hidden cross-subsidies are allowed to occur.

Some proponents of the pay-as-bid approach also claim that it is not necessary to pay existing units as much as new units because existing units will be not retired as long as they recover their individual short-run marginal costs. For example, it may be claimed that an existing coal unit whose short-run marginal cost of operation is $45 per MW-hour should only receive $49.50 per MW-hour when operating (a 10% rate of return) even when the marginal unit dispatched during a given hour is a combined cycle gas unit whose short-run marginal cost is $60 per MW-hour. The claim would be that the $15 per MW-hour margin above short-term marginal costs for the coal unit if the single clearing price model were used, would be excessive. The fallacy of this argument, however, is that the developer of the coal plant would not have built the facility in the first place if it understood that the plant would only receive the $4.50 margin in all hours. The developer's decision to build (and the ability of the developer to recover its capital expenditures) was premised on its perception that the coal unit would have the opportunity to receive the infra-marginal revenues when units with higher short-run marginal costs are on the margin.

Similar considerations come into play in making decisions regarding whether to upgrade an existing unit. PSEG Power's Hudson 2 coal-fired generating plant is a case in point. PSEG Power was faced with a decision whether to retire this plant or to undertake approximately $900 million in environmental upgrade capital expenditures. One of the primary drivers of PSEG Power's decision to undertake the project was the expectation that Hudson 2 would recover infra-marginal revenues when units with higher production costs were on the margin. If Hudson 2 could only recover its marginal cost of operation at all times, it is very unlikely that PSEG Power would ever have made this investment.

2) Long-term Contracts Are Available At Present And Will Become More Wide-spread as Markets Mature

The criticism that suppliers are somehow unwilling to enter into long term contracts is unfounded and contradicted by the facts. Long term contracts are widely used in competitive procurements such as the procurement recently conducted by PPL. The Basic Generation Service auction in New Jersey and Standard Offer Service auction in Maryland are examples of other instances in which there has been broad interest by the industry in long term arrangements.

Long-term bilateral contracts outside of these structured procurements, admittedly, are not as prolific. Incentives for entering into long-term bilateral contracts are present when price and risk allocation are properly aligned. For this to occur, however, markets need to mature to the point that both buyers and sellers have a degree of confidence in predicting reasonable market outcomes in the future. That is still not the case at present.

When the ISO markets were first implemented, there was an excess of generating resources that skewed expectations about future prices. During this time when many merchant generators were experiencing financial difficulties, they would gladly have entered into long term contracts for a small premium if buyers had been willing to do so. But LMPs and capacity values were so low that load servers preferred to rely on the spot market with the expectation that prices would always be low. Now that energy markets are reaching equilibrium and producing higher prices, many of those same buyers are complaining about the lack of availability of long term contracts at unrealistically low prices that they would deem to be acceptable. Thus, instead of recognizing that current prices more accurately reflect long-run costs than the repressed prices of several years ago, many buyers are now attacking the market construct itself.

PSEG ERT respectfully submits that, in these circumstances, the Commission can best promote long-term hedging contracts by stating its support for robust market designs such as PJM's wholesale market. Buyers will not be willing to enter into long-term arrangements until it becomes clear that these markets will not be dismantled or changed in ways significant enough to undermine fundamental market design elements upon which price determinations were based. The market should be able to mature once this recognition gains acceptance.

The Commission, moreover, could further promote long-term hedging by adopting policies in favor of transparently-designed service procurement auctions and requests for proposals. The Commission has already done a good job with the PPL wholesale contract. It may be beneficial for public power and industrial entities to retain independent consultants to give them objective reference prices which they could utilize in order to hold similar long term procurements or procurements along the line of the BGS/SOS auctions.

From the standpoint of consumers, moreover, the procurement approaches utilized by PPL and in the BGS/SOS auctions has been highly beneficial because it allocates most of the supply risks on the suppliers. This is appropriate because the suppliers are in the best position to manage these risks though fuel hedges, financial hedges or other actions. Suppliers, however, cannot easily manage transmission risks so that it is appropriate for these risks to be borne by the buyers.

Finally, the Commission should recognize that it can use long-term contracts as a means of promoting its public policy objectives. One area in which this is the case concerns demand response programs. Thus, the Commission could decide to mandate that a portion of load be served under real time pricing in order to provide incentives for demand response. Alternatively, the Commission could determine that it should require utilities with load serving obligation to lock in firm prices. These alternatives, of course, also need to be balanced against the risk of creating stranded contracts. History would suggest that 10-20 year contracts are too long, given the experience of stranded costs under QF contracts when market prices came down significantly. PSEG ERT would suggest three to five years as a maximum term.

3) The Commission Could Consider Incentives To Promote Desired Supply Diversity Provided That Markets Were Not Adversely Affected.

Some critics of PJM markets have claimed that there is no explanation for why developers have primarily chosen to construct new gas fired projects over generating units that use other fuels. There are very rational reasons, however, why gas has been the preferred fuel for new generation. First, the combination of capacity and energy payments in the market support gas-fired generation over other technologies at this time. Second, the risk that environmental regulations could radically change in the future supports the construction of gas-fired units. Because gas is relatively clean burning, it is less likely to become subject to problems of meeting increasingly stringent environmental standards.

It is important to recognize, moreover, that the price signals produced in the market may not always drive resource development towards desired social policy goals such as base plant development. For a long time, revenues were not sufficient to support any generation construction, let alone gas-fired generation. The development of the Reliability Pricing Model was designed to address that need. In the case of non-peaking units, however, much of the unit's revenues will need to come from the energy market. With declining gas prices and rising coal costs, market signals are unlikely to drive construction towards new coal units for the foreseeable future. Moreover, there is huge uncertainty about potential increases in cost in the near future dependent on carbon legislation.

The Commission thus should rightly be concerned that market signals alone may not drive policy choices. To the extent there are social goals to be met, it is entirely appropriate that the Commission take steps to achieve them. It is also incumbent on the Commission, however, to ensure that the measures taken do not undermine the integrity of the pricing signals relied upon by generators and investors to make prudent unit development and unit retention decisions. For example, requiring a utility to sign an out-of-market contract with one developer, who then bids into RPM at less than its actual cost of construction may undermine the operation of that market. This bid could clear the market at understated costs – thereby causing other needed units not to clear. Ultimately, serious reliability problems may ensue as only one generator will be compensated in a way that enables it to maintain its facility.

PSEG ERT recommends that the Commission consider measures such as tax credits and loan programs to promote resources that it deems to be desirable. These measures are effective incentives but are less likely to have broad adverse impacts on the markets. It is critical that the Commission be cognizant of how its actions affect the operation of wholesale markets and that it not adopt measures that would undercut competitive market outcomes.

4) Regulated Utilities Have Not Been Shown To Be Able To Serve Customers At Lower Cost Than Markets

Claims that so-called "regulated" utilities are serving customers at lower costs than customers served by markets are unfounded. The comparisons that supposedly support this conclusion are far more complex than is being suggested by their proponents. For example, markets run by RTOs first developed in areas of especially high costs – the eastern regions that are heavily urbanized. In addition to a higher land and labor costs, these areas have some of the highest environmental compliance costs of anywhere in the nation.[2] It is thus reasonable to expect that direct comparison of electric rates between (expensive) regions with markets and (less expensive) regions with "regulated" utilities will show that the regulated rates are lower. The comparison itself, however, is invalid. Rather, it is necessary to compare what rates would have been in expensive areas if the "regulated utility" model had been retained against the rates being charged under competition. This type of comparison shows that competition has placed downward pressure on prices through technological innovation and increased efficiency. This is apparent, for example, in the improved performance of virtually all kinds of generators in regions that have adopted competition models.[3]

PSEG ER&T respectfully submits that the Commission should maintain its focus on whether markets are producing just and reasonable rates. Focusing on apparent investment returns of particular companies for particular generating units would be counterproductive. For one thing, the costs associated with operating these facilities may not always be superficially apparent. For example, costs associated with growing environmental challenges need to met through the infra-marginal revenues that these plants recover. Further, attempts to reduce returns could lead to declines in innovation and growth, precisely the types of activity the Commission should be encouraging so as to supply consumers at the lowest possible cost.

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[2] *See* "Causes of Rising Electric Prices," dated January 2008, pp. 4-7 (attached) prepared by PSEG Services Corporation. As noted there on p. 6, as of the time the report was prepared, "restructured states have implemented [Renewable Portfolio Standard] policies that will ultimately deliver almost twice the amount of emission free power by 2020 as regulated states." .

[3] *Id.*, p 8. (noting that "[n]uclear plant capacity factors have improved from an average of 70% in 1992 to almost 90% in 2006. Refueling outages have been reduced from an average of 88 days in 1992 to 39 days in 2006.")

IV. CONCLUSION

PSEG ERT respectfully submits that, over the long term, PJM's robust market mechanisms will provide a highly effective means of assuring that Pennsylvania consumers have access to reliable power supplies at the lowest possible costs. If markets are allowed to function without improper interference, competition will best serve consumers in Pennsylvania and the other PJM states.

Respectfully submitted,

PSEG Energy Resources & Trade LLC

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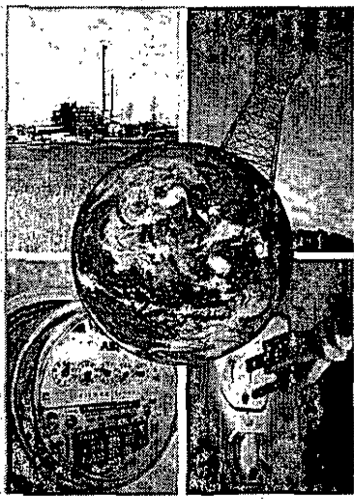
ATTACHMENT



The Causes of Rising Electricity Prices

January 2008

PSEG

The Causes of Rising Electricity Prices: Executive Summary

Increases in retail electric prices across the nation have raised questions regarding the underlying causes. Although restructured regional markets in the northeast, mid-Atlantic and elsewhere[1] have brought many benefits to customers, they have not been immune from these price increases. Benefits include the reduction of fuel burned and an increase in demand side resources, and these have helped to mitigate price increases and to lower the level of harmful air pollution that would otherwise be emitted into the air. Some parties have asserted that the restructuring of electric markets, both at the wholesale and retail level, has been the primary cause of such price increases, and have even asserted that centralized markets operated by Regional Transmission Organizations (RTOs) are producing unjust and unreasonable wholesale power prices[2] compared to fully regulated markets. The object of these efforts is, of course, to get regulators to re-regulate and lower prices. In their zeal, these parties have confused correlation with causation, have failed to recognize that the most significant drivers of price increases are completely independent of regulatory structure, and have ignored benefits that restructuring has brought to customers.

When considering these factors, the more appropriate conclusion is that restructuring of the electric industry has had a positive impact on the efficiency of the market and the environmental footprint of the generation sector, and prices have been influenced more by changes in input fuels and the difficult environmental choices that face policy makers than by the regulatory structure by which wholesale and retail markets provide prices to consumers. Some of the most important points to consider are:

1. **Efficiency improvements in the production of electricity have helped decrease fuel usage and mitigate the impact of higher fuel costs.** One of the most significant benefits of regional wholesale markets is the improvement in dispatch of generation plants, which minimizes the operation of older, less efficient plants, saving fuel and the emission of harmful pollutants. States that have not restructured at the retail level have benefited from the efficiency improvements resulting from the creation of regional wholesale markets. And non-RTO states have benefited from these organized markets by buying and selling power from them when it is cost effective to do so, or when they have a shortage of power.

2. **The growth of demand side resources.** Restructured markets have been in the forefront of developing mechanisms to allow demand side resources to compete effectively against supply. Demand response helps to keep prices low, particularly in times of peak demand, and also reduces pollutants such as ground-level ozone and CO_2 by lowering the need for those power plants to run.

3. **The differential impact of underlying costs such as input fuel.** One of the largest drivers of electricity costs is the input fuel. The cost of all fuels has risen, but the price of natural gas has risen much more than the price of coal, which is a more prevalent fuel source in restructured

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[1] For purposes of this analysis, the definition of restructured states will follow the convention used in a recent Power in the Public Interest report that classified California, Connecticut, Washington DC, Delaware, Maine, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Rhode Island, and Texas as restructured to the retail level. The other 37 states were classified as regulated.

[2] Complaint of the parties to FERC ANOPR Dockets RM07-19-000 and AD07-7-000, December 17, 2007, page 4.

states. In addition to fuel, there are several other costs that have risen more in restructured states than regulated states.

4. **The differential impact of environmental regulations and differing environmental policy goals.** For over 20 years, policy makers in many of the states identified as restructured have been environmental leaders, addressing and mitigating the risks associated with issues such as power plant air emissions and global warming. As part of that leadership, these states have also made conscious decisions to reduce air emissions associated with the generation of electricity, with the understanding that tighter emissions requirements would increase energy costs, while providing environmental benefits to the public. Customers in these states have supported this public policy direction. In addition, existing emission regulations have placed a greater compliance burden on restructured states than regulated states, further driving prices upward.

5. **Oversimplification of a complex market**. Restructuring has proceeded at a different pace, with different rules and approaches in each state. Many critics treat state level restructuring as an "event," when in actuality it is an on-going and evolving process occurring at different speeds within each state. The terms and conditions by which each state restructured its utilities is unique; some states originally imposed rate freezes, some rate discounts, and some even imposed rate adders to encourage retail shopping. Some states now allow all customers to shop; some only allow larger customers to shop, and some states have joined regional wholesale markets but have not restructured at the retail level. The manner in which power is procured for customers who do not choose alternate suppliers is different from state to state; procurement methods, length of contracts, and contract terms all differ. All of these factors make it difficult to simply label a state as restructured when the reality of the market is much more complex.

FERC has consistently confirmed the benefits of competition and has worked to foster an environment that seeks to support competitive markets while retaining its essential role in providing regulatory oversight in wholesale markets. Its recent Advanced Notice of Proposed Rulemaking (ANOPR) has identified four specific market issues[3] that it is seeking to review in order to improve the operation of organized wholesale markets. Critics have used this opportunity to challenge organized competitive wholesale markets in principle, but as Chairman Joseph Kelliher has stated, "...the central question facing the Commission is not whether competition is sound policy. That question has been asked and answered three times by Congress, as recently as two years ago. The central question is what can the Commission do to make wholesale markets more competitive?"[4]

Cost Drivers

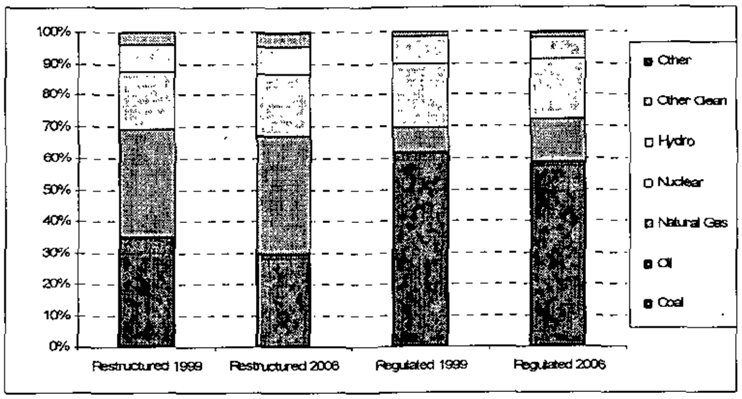
Input fuel prices: The increase in input fuel prices between 1999 and 2006 are well documented. In review, the price increases have been:

- Natural Gas – Average Henry Hub gas price has risen over 230% between 1999 and 2006
- Fuel Oil – Average price of distillate has risen over 220% between 1999 and 2006
- Coal – Average price of bituminous coal has risen 42% between 1999 and 2006

[3] The four issues are: the role of demand response in organized markets, increasing opportunities for long-term contracting, strengthening market monitoring, and the responsiveness of RTOs and ISOs to customers and stakeholders.
[4] Statement of Chairman Kelliher, June 21, 2007.

The extent to which input fuel prices impact electricity prices is dependent on the mix of power plant fuels within the region. Figure 1 provides clear evidence that restructured states have faced much greater input fuel cost pressure. The regulated group generates almost twice the energy from higher-emitting fuels (coal and oil) as the restructured group (59% vs. 30%). By contrasting the price increase differential between natural gas (230%) and coal (42%), it is apparent that electric prices in restructured regions have faced much greater cost pressure. And while both groups have seen reductions in the percentage of generation coming from higher emitting fuels since 1999, the reduction in the use of these fuels is higher in the restructured states (14.3%) than the regulated group (4.3%).

Figure 1 Generation by Fuel Type (as a % of total generation)



Societal costs embedded in rates: In addition to power supply costs, retail rates are impacted by the level of spending on societal benefits programs, particularly programs designed to advance energy efficiency. As electric prices have risen, greater attention and funding has been directed to these programs. The American Council for an Energy-Efficient Economy (ACEEE) ranks the states in terms of their commitment to energy efficiency policies, including spending on demand side and energy efficiency programs[5]. The difference in commitment and spending between restructured and regulated states is significant. More than three-quarters of restructured states were ranked in the top 20 of the ACEEE report (based on 2004 spending levels), while only 27% of the regulated states ranked in the top 20. In terms of energy efficiency program spending, the 2004 national per capita average was $4.93. Per capita spending by restructured states was $8.07, 63% above the national average, while per capita spending by regulated states was $2.81, 42% below the national average. Similar trends can be seen in prior years' reports going back to 1999, when social spending was near its low point. This data provides evidence that restructured states have made policy decisions to promote more aggressive deployment of energy efficient technologies and measures, even if short-term consumer rates increase, with the view that long-term success of the programs will lower bills overall by reducing consumption.

Cost of doing business: The majority of the restructured states are heavily populated regions with cost structures significantly higher than average. An annual survey published by the Milken Institute provides data on the relative cost of doing business in all states[6]; it has developed an index composed of local wages, taxes and rental costs. The most recent survey indicates that seven of the ten most expensive

[5] ACEEE report "The State Energy Efficiency Scorecard for 2006."
[6] The Milken Institute is a publicly supported, non-profit economic think tank that does research to support policy initiatives that can improve the lives and economic conditions of diverse populations in the U.S. and worldwide. Electricity is normally included in the index, but was removed from the index for this white paper.

states to do business in are restructured states. The index for restructured states averaged 106.1, for regulated states the average was 93.5. The national average was 96.7.

Data assumptions and analysis: Reported results regarding price increases can change significantly depending on the time frame chosen and the selection of restructured states. As an example, a recent report published by Power in the Public Interest (PPI) concluded that the price gap between restructured states and regulated states widened from 35% to 56% between 1999 and 2007, and that deregulation was the primary cause of the growth in this gap. Several states, including New Jersey, implemented mandatory price discounts as part of its restructuring process in 1999. This choice of starting year artificially lowers the starting price and therefore yields a higher percentage increase over time. Using a starting year of 1996 or 1997 would more accurately reflect the impacts of retail choice since that time frame reflects retail prices prior to the implementation of any mandated price discounts associated with state deregulation. There is also no generally accepted list of states that have restructured due to the differences in retail access rules among the states. Restructuring rules may differ by utility, customer size or customer type, and a few states have either partially or fully suspended retail access to customers.

Any analysis, therefore, will be greatly influenced by the choice of states and the time frame for the data. Several other recent reports from credible sources have used the same Energy Information Administration (EIA) data but have reached different conclusions compared to those that have been critical of restructured markets. For example:

- A 2007 Brattle report [7] concluded that regulated and restructured states saw virtually the same increase in prices between 1997 and 2006.
- A 2007 NERA report [8] found that restructured states without a price freeze saw a 19.2% increase between 1995 and 2005, while un-restructured states saw a 21.3% price increase.
- A recent analysis conducted by Energy Strategies and Bates White [9] comparing prices in PJM and Southeastern states concluded that between 1998 and 2005 PJM retail prices increased 7.8% while Southeastern prices increased 23.7%.
- A recent report published by the Analysis Group [10] concluded that restructured states witnessed a 30% increase in prices between 1995 and 2007, while regulated states saw a price increase of 26%. [11]

Differing environmental agendas and impacts

The mix of generation plants in a region is not simply a function of available natural resources, access to fuel supply, or developer choice of technology. Since the enactment of the 1990 Clean Air Act Amendments, many restructured states have made conscious policy decisions designed to move their in-state generation fleets away from higher emitting fuels such as coal and fuel oil, or further tighten the emission controls of such plants. These decisions were made with full knowledge that such a shift would result in an increase in electricity prices.

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[7] J. Pfeifenberger and A. Schumacher. Brattle report presented at the 2006 NASUCA meeting at Miami, FL.

[8] E. Meehan. NERA report presented at a November 5, 2007 COMPETE/EPSA symposium at Washington DC.

[9] H. Axelrod, D. DeRamus, and C. Cain, "The Fallacy of High Prices" *Public Utilities Fortnightly*, November 2006.

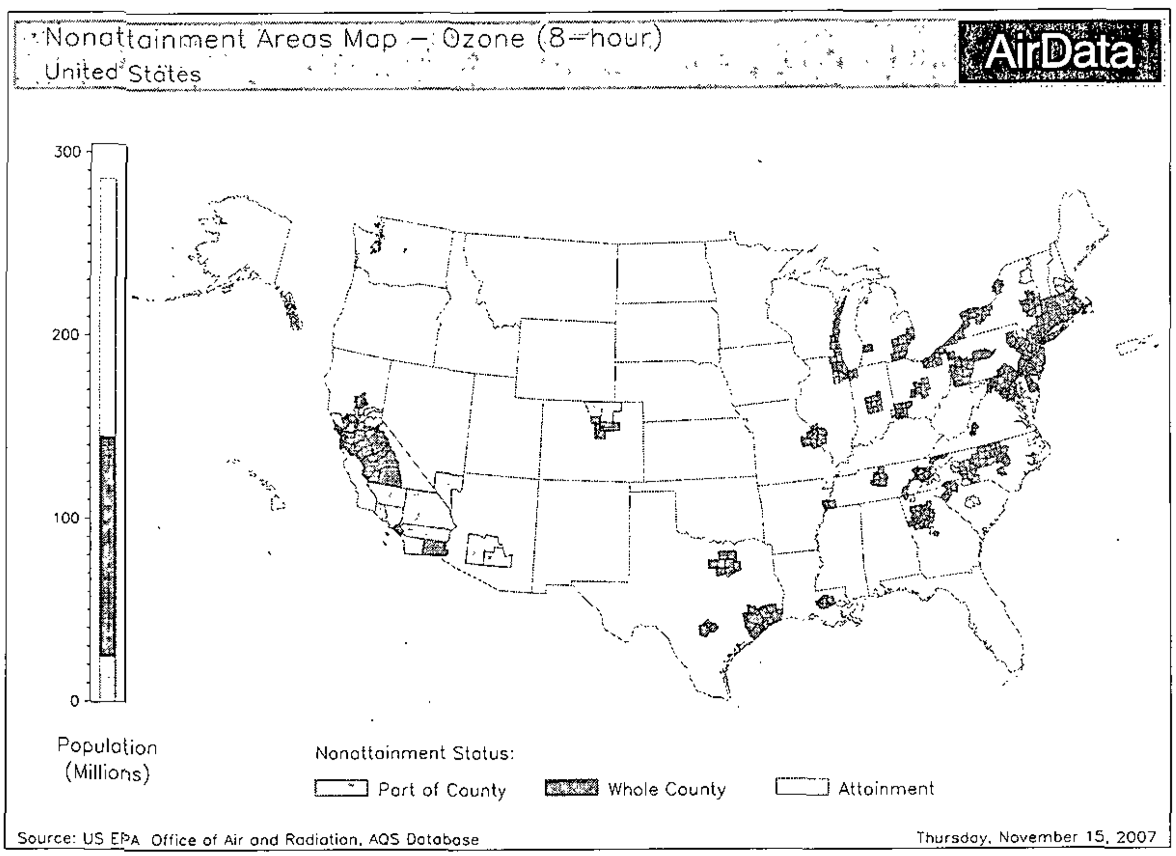
[10] S. Tierney "Decoding Developments in Today's Electric Industry – Ten Points of the Prism", October 2007.

[11] This data were erroneously reported by the New York Times, which reported this data as a 15% higher increase in prices for restructured states, actual difference cited in the report was 4%.

In addition to these policy goals, the regulations implemented as part of the 1990 law have placed a greater burden of compliance on restructured states. Locationally, restructured states are particularly affected by the requirement for 8-hour ozone regulations. Eleven of 13 restructured states, as well as Washington DC, have all or portions of their states classified as "non-attainment[12]" for 8-hour ground-level ozone, while 19 of the regulated states are in compliance throughout the state (figure 2). Generators within non-attainment zones have additional NOx emission control burdens placed upon them, increasing their operational costs.

Looking forward, the Clean Air Interstate Rule (CAIR) that will come into effect in 2009/2010 timeframe will focus on the transport of ozone precursors and fine particulate in the eastern half of the country. These transport rules have been designed to challenge upwind states (that are in attainment zones) to reduce emissions because of the impact on downwind states' air quality. Pointedly, emissions reduction will be most required from the regulated states in the area that are impacting restructured/non-attainment states downwind, and will begin to impose additional costs on regulated generators to which they are currently not exposed.

Figure 2 8-Hour Ground-level Ozone Non-attainment Areas



[12] Non-attainment is a legal status indicating that a region violates the air quality standard for a pollutant, in this case, ground-level ozone. Once a region has been designated, state and local governments must implement plans to reduce the air pollutant emissions contributing to ground-level ozone concentrations.

The resulting comparative emission profiles between restructured and regulated states provide strong evidence of the impact on prices of more aggressive environmental policies and technology limitations due to federal regulations (figures 3, 4, and 5).

Figure 3 2005 SO_2 emissions (lb/MWh)

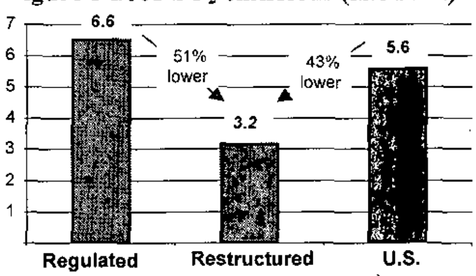


Figure 4 2005 NOx emissions (lb/MWh)

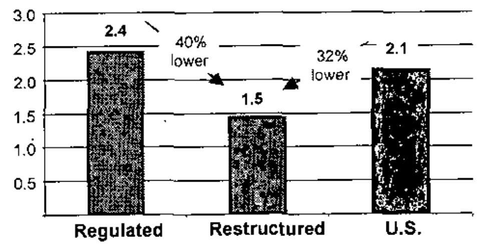
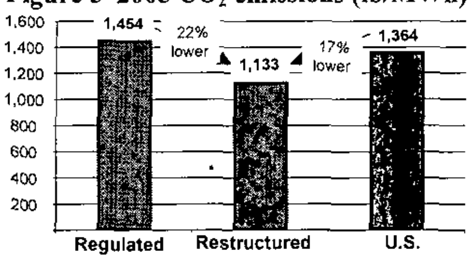


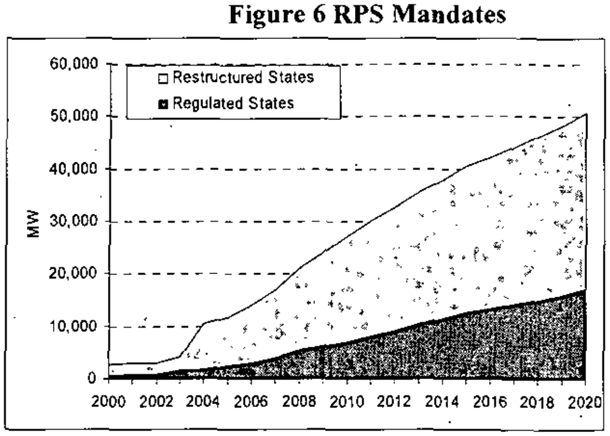
Figure 5 2005 CO_2 emissions (lb/MWh)



Source: EIA State Electricity Profiles

The implementation of aggressive environmental policies goes beyond the additional emissions controls. Since the late 1990s, many state policy makers have developed Renewable Portfolio Standards (RPS) to encourage the development of low and non-emitting generation technologies. Restructured states have been much more aggressive in the development of RPS policies (figure 6). Once again, policy makers have consciously made the trade-off between improved air quality and power prices, as recent government and industry studies[13] have shown that the cost of most new renewable technologies are above current market prices. Over time, it is hoped that these technologies will mature and become more cost competitive with conventional generation.

Figure 6 RPS Mandates



As figure 6 shows, restructured states have implemented RPS policies that will ultimately deliver almost twice the amount of emission-free power by 2020 as regulated states. For 2007, restructured states are delivering about 80% all new, clean power. Policy makers, with support from the public, have made a policy choice to pursue clean generation technologies with the understanding that the cost would be reflected in higher electricity prices.

Source: Union of Concerned Scientists

[13] EIA "Annual Energy Outlook 2007" and a Navigant report to Edison Electric Institute, February 2007, are two examples of recent studies on the comparative levelized cost of electricity of various renewable and conventional generation technologies.

Many of the restructured states have also taken aggressive stances in initiating programs that will lead to the control and abatement of carbon emissions. The Regional Greenhouse Gas Initiative (RGGI) includes nine of the 13 restructured states. Slated to begin operation in 2009, the RGGI agreement will put a cost on carbon emissions from power plants within state boundaries, once again putting upward pressure on retail prices in exchange for combating an environmental problem. California, another restructured state, has passed strong legislation attacking the carbon emission problem, setting goals for abatement, and even disallowing long term contracting with out-of-state coal based generators. While some regulated states are beginning to analyze the carbon problem, none have taken steps as aggressive as states in the Northeast and California.

Additionally, the RGGI states have expressed heightened concern over the increased importation of electricity due to the CO_2 compliance costs incurred by in-RGGI generation. As with CAIR, the concern stems from regulated states importing power into restructured/ RGGI states.

Positive impacts from restructuring

Many of the critics of restructuring vastly oversimplify the complexity and impact of the restructuring of the electric power industry over the past ten years. Critics often single out one element of deregulation, access to retail prices for industrial customers, as the litmus test of success of competitive electric markets. In doing so, they ignore the impacts of a multitude of changes that have taken place in the industry, and ignore the pre-existing conditions that originally gave rise to the desire for restructuring.

The original impetus for restructuring of the electric markets was the poor performance of regulated electric markets in the 1980s and early 1990s, compared to the tremendous success of deregulation of the wholesale natural gas markets in the late 1970s. Several electric utilities were brought to the brink of bankruptcy due to the huge cost overruns of nuclear plant construction programs. One company, Long Island Lighting Company, ultimately had to be bought out by the State of New York due to the failure of the Shoreham nuclear plant. Nuclear plants that had gone on-line were running at very low capacity factors. Utilities were straddled with high priced power under mandated Public Utility Regulatory Policy Act (PURPA) contracts. Prices were rising, and government solutions were simply making matters worse, not better. The passage of the 1992 Energy Policy Act created the concept of merchant generation and ensured access of non-utility generators to transmission lines. As a result, many high-priced states began to develop policies to take advantage of this new opportunity.

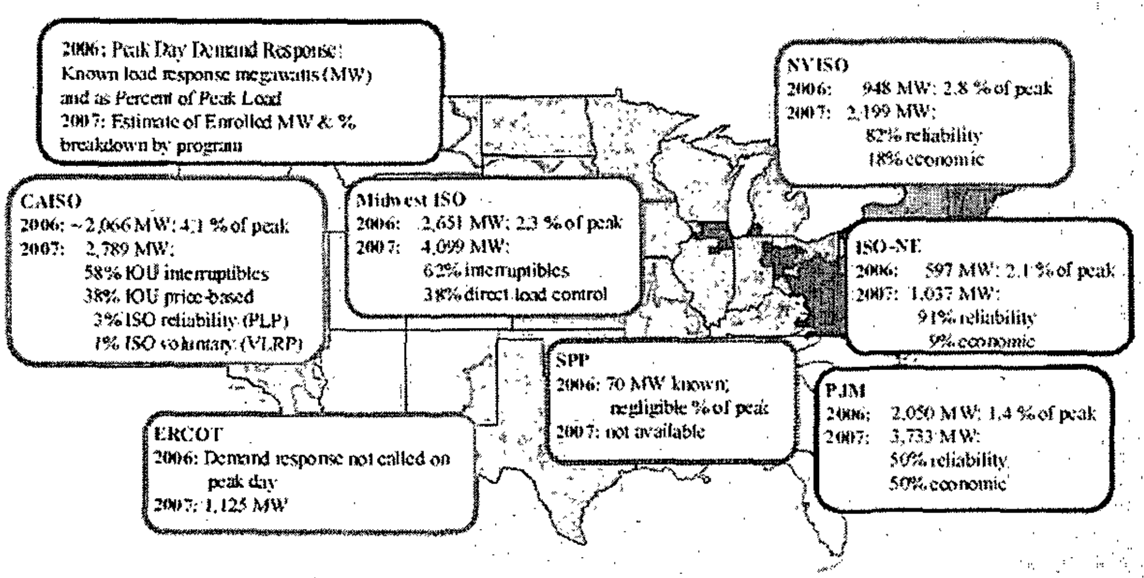
Since that time federal regulators and policy makers have been working to improve upon the original intent of the 1992 law. At the federal level, FERC has implemented many changes to the structure and operation of the transmission network to allow merchant generators greater access to critical infrastructure. In doing so, merchant generators have been able to compete to serve load by offering more competitive prices for energy. In addition, the imposition of multiple transmission rates on inter-regional sales has been minimized or completely eliminated, allowing for more economic flow of lower cost generation. FERC has promoted the development RTOs, which have formed both in regions with and without retail access to allow wholesale markets to function more efficiently, even among vertically integrated utilities.

Large, multi-state RTOs such as PJM, Southwest Power Pool (SPP), the Midwest ISO (MISO), and the New England ISO have provided enormous benefits to customers, even in regions that have not opened up competition at the retail level. One of the most significant benefits is the improvement in generation plant dispatch efficiency. Prior to the creation of regional markets, each of the dozens of utilities within a region dispatched, or called on, the generation plants within its own service territory to provide power, based on the need of its service territory customers. Without access to the lower cost plants in other regions, utilities often called upon older, less efficient plants as the need arose. When imbalances between utilities arose, they would often change the output of all plants to rebalance supply and demand. RTOs consolidated this dispatch function, and were able to reduce the need to call on older plants by better utilizing the more efficient plants for the benefit of the entire region, instead of just the immediate area surrounding the plant. This saves fuel, and thereby lowers the amount of pollutants going into the atmosphere.

RTOs have been instrumental in the development of more market-based, demand side options for customers. A recent FERC report provided strong evidence of the robust growth of demand side resources over the past few years (figure 7). Demand side resources serve several purposes: 1) help to maintain the reliability of the grid during times of high demand, which benefits all customers in the RTO; 2) allow participating customers to take economic advantage of the energy and capacity price signals that are available to them in the competitive wholesale market, helping control their own energy budget; and, 3) lower capacity and energy prices over the larger market, which also benefits all customers.

Figure 7 Changes in Demand Response Programs among Organized Markets

Figure II-1. Summer 2006 demand response contributions and summer 2007 program enrollments



Source: FERC

On the plant operations side, restructuring has driven plant operators to achieve efficiencies never before seen in the industry. Nuclear plant capacity factors have improved from an average of 70% in 1992 to almost 90% in 2006. Refueling outages have been reduced from an average of 88 days in 1992 to 39 days in 2006.[14] Merchant operators have led this success story. And while both merchant and regulated operators have improved their operations, it has been the merchant operators who have been in the forefront of efficiency improvements, and merchant operators still, on average, lead the industry in operating efficiency.

[14] Nuclear Energy Institute.

Final Thoughts

This paper attempts to address the complex question of the causes of increasing electric prices. In identifying the various cost drivers that impact electricity prices, it is clear that deregulation cannot be viewed as a driver of electric cost escalation. Rather, the evidence indicates that the more broadly defined restructuring of the electric market has brought many benefits to all customers, regardless of the retail price construct with which they are served. FERC, through its ANOPR, has acknowledged that the wholesale power market is dynamic, subject to rapid changes, and it must constantly evaluate changes in policy in reaction to these changes. The collaborative work among utilities, generators, consumer groups, state and federal regulators and policy makers has resulted in a robust competitive marketplace that benefits both the environment and customers. This collaborative effort needs to continue so that we can effectively address the energy challenges we face, while maintaining our commitment to stewardship of the environment.

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