UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference
Demand Response in Organized Markets **Docket No. AD08-8-000**

Prepared Remarks of Robert L. Borlick, Energy Consultant
May 21, 2008

Mr. Chairman and members of the Commission, thank you for providing me with this opportunity to present my views on the value of demand response in organized markets and on comparable compensation of demand response resources. My views are based on my more than thirty years of experience with the electric power industry, most of which has been in the area of competitive wholesale market design.

I. EXECUTIVE SUMMARY

Demand response provides both direct and indirect benefits; however, it also incurs costs.

The direct benefits consist of avoided capacity and energy costs of the displaced supply resources. The indirect benefits are the mitigation of generator market power and the reduction in capacity payments required to attract new supply.

The costs associated with demand response consist of the investment in metering and telecommunications infrastructure, plus the operating costs of program implementation. In addition, there is another cost that is often overlooked – the foregone value of the electricity the demand response (DR) provider did not consume. Although not directly observable, this cost can be approximated if one has an estimate of the DR provider's price elasticity of demand.

The value of demand response in controlling generator market power has a theoretically sound foundation and has been empirically confirmed through two-sided bidding experiments. When sufficient demand response capability is in place to control generator market power caps on energy prices can be relaxed.

One benefit that is not fully appreciated is the potential for demand response to reduce, and ultimately to eliminate, the need to pay generators capacity payments. This evolution will not occur unless wholesale market designs fulfill four conditions that are necessary and sufficient to eliminate the "missing money" problem. This Commission has the key role in putting in place those conditions.

In addition to offering significant improvements in economic efficiency an energy-only market would eliminate the need for administratively imposing reliability standards that consumers do not need and do not want to pay for.

Regarding the issue of appropriate compensation for demand response resources, the economically efficient level of compensation for a MWh of energy reduction is the applicable locational marginal price (LMP) less the charge the provider avoids through its retail tariff. Any greater compensation constitutes a subsidy borne by other consumers, and possibly by generators in the short-term.

In addition to the above compensation, any demand response resource that reliably reduces load during times of supply shortage should be paid the same capacity payment that a generator of comparable reliability receives. This does not require the DR responder to be 100 percent reliable any more than a generator must be 100 percent reliable to qualify for such payments.

II. VALUE OF DEMAND RESPONSE

Demand response can play a number of roles in wholesale markets. It can reduce load in response to high hourly energy market prices (Economic DR) or when instructed to do so when operating reserves become scarce (Emergency DR) or when instructed to do so to counteract contingencies or to follow load (Ancillary Services DR). While these roles technically differ, all of them substitute load reductions for generation. Thus, all demand response produces economic benefits and incurs costs that are immediately realized and directly measurable; however, demand response also offers indirect benefits that are not immediately realized and not so easily quantified.

DIRECT ECONOMIC BENEFITS

The demand response benefit that is immediately realized is the avoided cost of generation fuel and other variable costs. In addition, to the extent that the demand response resource can be relied on to reduce load during scarcity conditions, the resource can substitute for generation for resource adequacy purposes. This produces a benefit equal to the avoided cost of generating capacity. Finally demand response allows reduced investment in transmission and distribution networks.

Figure 1 presents a rough estimate of the average annual savings that a 5 percent reduction in non-coincident peak demand would yield over a 20 year period, broken into the aforementioned three components.[1] The present value of these total savings for the 20 year period is about $35 billion, expressed in real, 2005 dollars. While one can take issue with the assumptions and methodology used to derive this estimate, it appears reasonable as a first-order approximation. The important point illustrated in Figure 1 is that the lion's share of the benefit of demand response is the avoided capacity cost.

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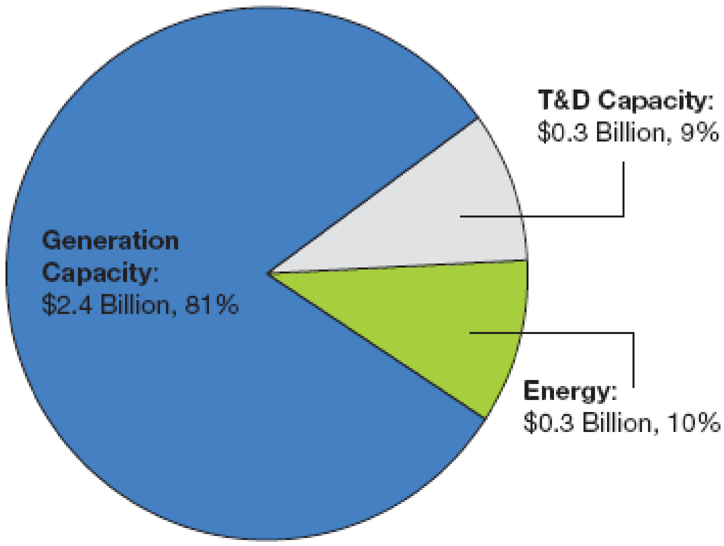
[1] Faruqui, Ahmed, et al, *the Power of Five Percent*, Brattle Group Discussion Paper, May 16, 2007. Available at: http://www.energetics.com/MADRI/pdfs/ArticleReport2441.pdf

Figure 1
Estimated Average Annual Benefits Produced By a Five Percent Reduction in Non-Coincident Peak Loads (2007 dollars)



Source: The Brattle Group

DIRECT ECONOMIC COSTS

While there are clear economic benefits that flow from demand response, there are also costs involved, some of which are routinely ignored. For example, the savings presented in Figure 1 are not adjusted for *any* costs, thereby substantially overstating the *net benefits* to be derived from the assumed reduction in peak loads.

All demand response programs involve direct costs of implementation such as investment in equipment and related operating costs that enable the DR provider to respond to wholesale market price signals and/or to dispatch instructions. In addition, there are typically some program administration costs borne by the customer's Load Serving Entity (LSE) and possibly by the ISO/RTO and Curtailment Service Providers (CSPs). Generally these costs are transparent and properly accounted for in benefit-cost analyses. In contrast there is another quite significant cost that is often neglected – the DR provider's foregone value of the electricity not consumed.[2]

When customers consume electricity they are actually consuming services that the electricity is converted into, i.e., light, heat, mechanical energy, electronic device outputs, etc. These services

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[2] The Brattle Group discussion paper cited above includes estimates of the costs of installing meters and communications infrastructure to achieve a five percent reduction (i. e., $26 billion) but it does not mention consumers' foregone value of service.

have value, either in the form of productivity for a business enterprise, or in the form of comfort and convenience for a residential customer. In order to produce a valid benefit-cost analysis, the value lost through load curtailment must be accounted for. Although rather obvious, this cost is often ignored, or it is excluded based on the rationale that it is too difficult to quantify. However, if one has an estimate of the DR provider's price elasticity of demand one can monetize the loss associated with foregone consumption, as I demonstrate in Appendix A. In recent years price elasticity estimates have emerged from a number of demand response pilots.

INDIRECT ECONOMIC BENEFITS

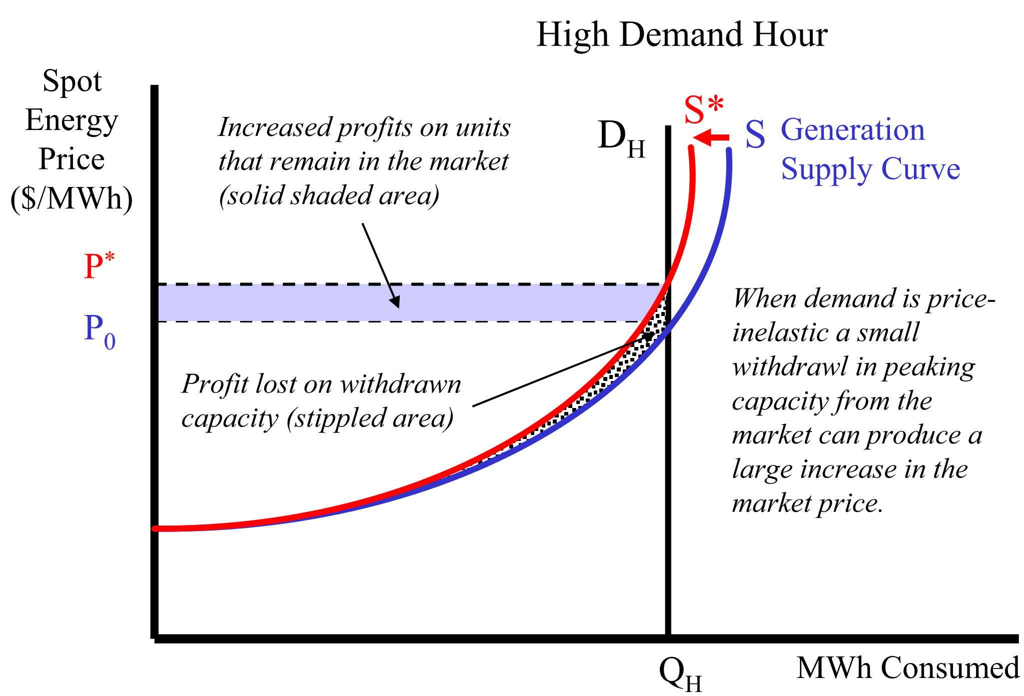
Demand response produces other benefits that are not immediately realized and not easily quantified, arguably the two most important being:

- mitigating generator market power
- reducing the need for capacity payments to generators.

Mitigating Generator Market Power

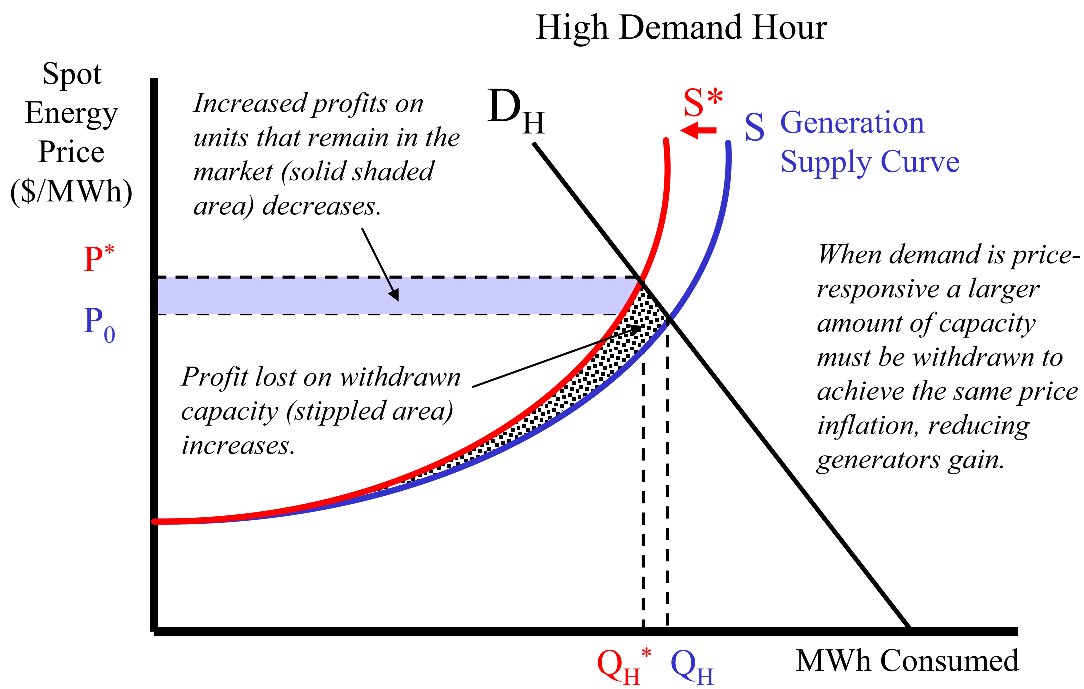
Generator market power arises because suppliers with diversified portfolios of generation assets can increase their profits from spot market sales by withholding from the market some high variable-cost peaking units in order to drive up spot market prices and consequently the profits earned by its low variable-cost units. This is illustrated in Figure 2.

Figure 2
Generator Market Power Illustrated



Demand response makes the exercise of market power less profitable by increasing the amount of capacity that must be withheld to achieve a given increase in spot market price. This forces the withholding parties to suffer larger foregone profits associated with the capacity withheld, as shown in Figure 3.

Figure 3
Demand Response Reduces Generator Market Power



The value of demand response in mitigating market power has been empirically demonstrated through experiments in market bidding behavior conducted at George Mason University and also at Cornell University.

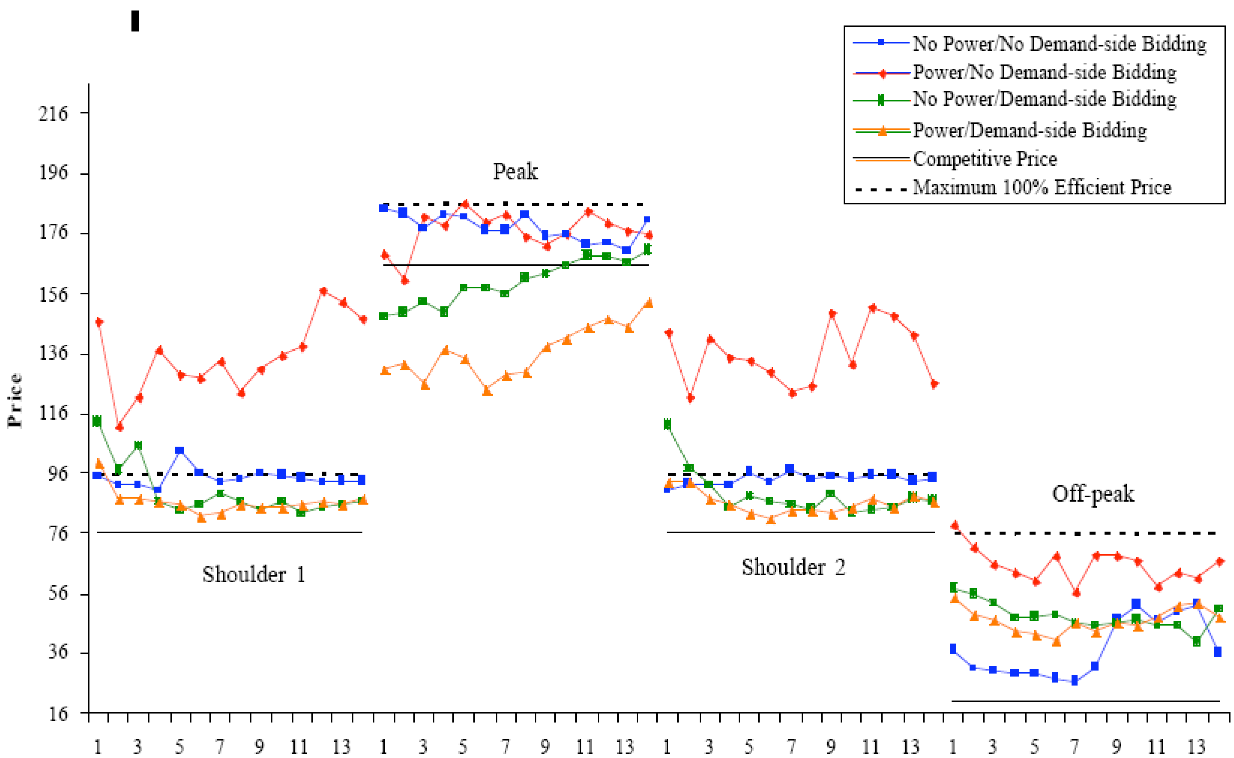
Steven Rassenti, Vernon Smith and Bart Wilson conducted two-sided power auction bidding experiments in 2002.[3] The experiments produced spot market electricity prices under various scenarios of generation ownership concentration both with and without demand-side bidding. The average prices produced by each scenario are shown in Figure 4.

Based on these results the authors concluded:

[3] Rassenti, Stephen J., Smith, Vernon L., and Wilson, Bart J., *Controlling Market Power and Price Spikes in Electricity Networks: Demand-Side Bidding*, Interdisciplinary Center for Economic Science, George Mason University, December 2002. Available at: http://www.pnas.org/cgi/content/abstract/0437942100v1.

> Our results … indicate that the distribution of ownership of a given set of generating assets can contribute markedly to the exercise of market power…. Moreover, having established this, we also find that the introduction of demand-side bidding in a two-sided auction market completely neutralizes the exercise of market power and eliminates price spikes. The obvious policy conclusion is that empowering the wholesale buyers provides a completely decentralized approach to the control of supply-side market power and the control of price volatility.

Figure 4
Average Market Prices With and Without Demand Response (GMU Experiment 2002)



Source: Rassenti, Smith and Wilson, ICES, George Mason University.

In 2001 Richard Schuler began conducting two-sided auction experiments at Cornell University.[4] These experiments simulated buyers' consumption decisions regarding purchases from the real-time market, whereas, the George Mason experiments simulated Day-Ahead market decisions. Although the approaches were different, both demonstrated that demand-side bidding suppressed the exercise of generator market power.

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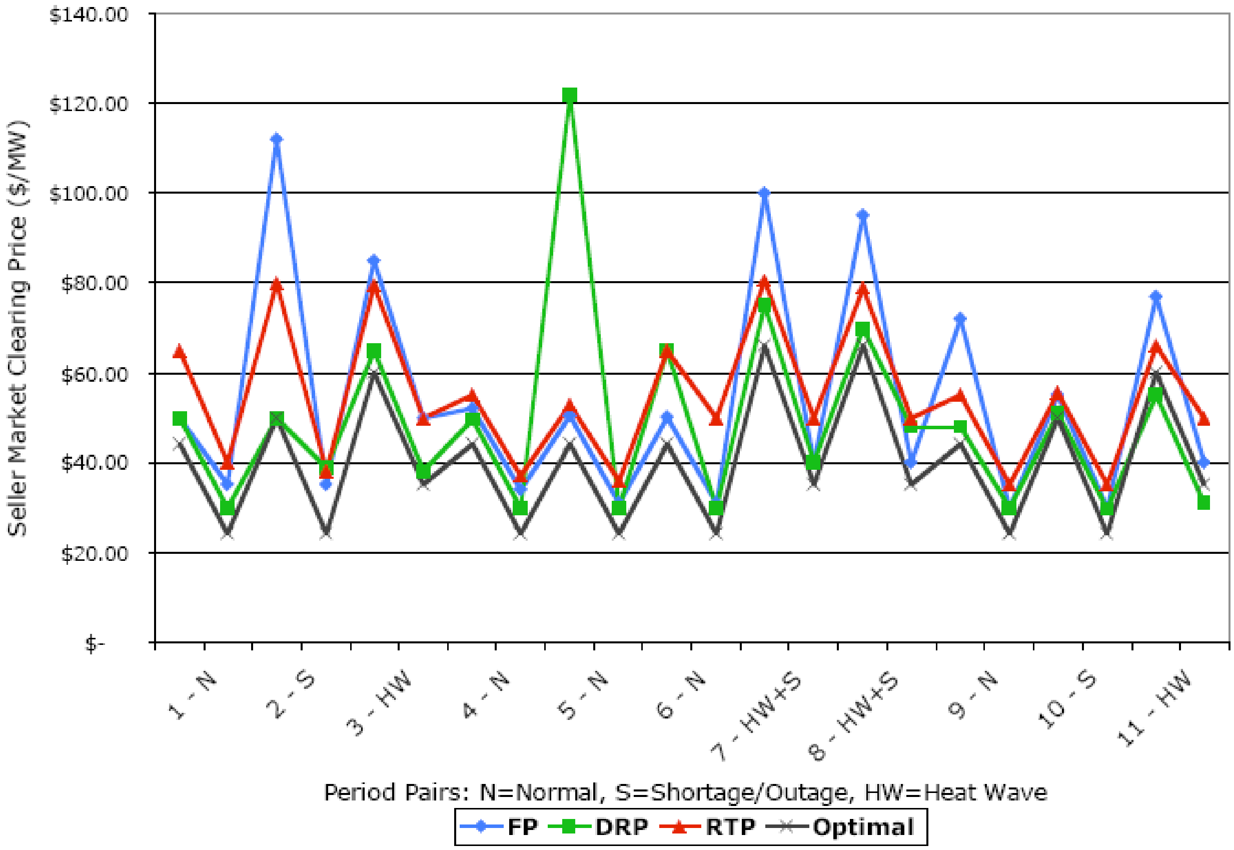
[4] Schuler, Richard E., William Schulze, Ray Zimmerman and Shmeul Oren, Structuring Electricity Markets for Demand Responsiveness: Experiments on Efficiency and Operational Consequences – Final Project Report, PSERC Publication 04-33, October 2004.

The Cornell experiments produced market prices over a range of scenarios for 22 different day-night periods, as shown in Figures 5 and 6.

Figure 5
Observed Market Prices With and Without Demand-Side Bidding

(Cornell Experiment 2003)



Source: Schuler, Schulze, Zimmerman and Oren, PSERC.

In the **FP** and **RTP** scenarios the buyers were served under a fixed-price retail tariff and a real-time pricing tariff, respectively. Under the **DRP** scenario they were served under a tariff that closely resembles the New York ISO's current Emergency Demand Response Program, which pays customers the market price for load reductions achieved relative to their normal loads under the fixed-price tariff.

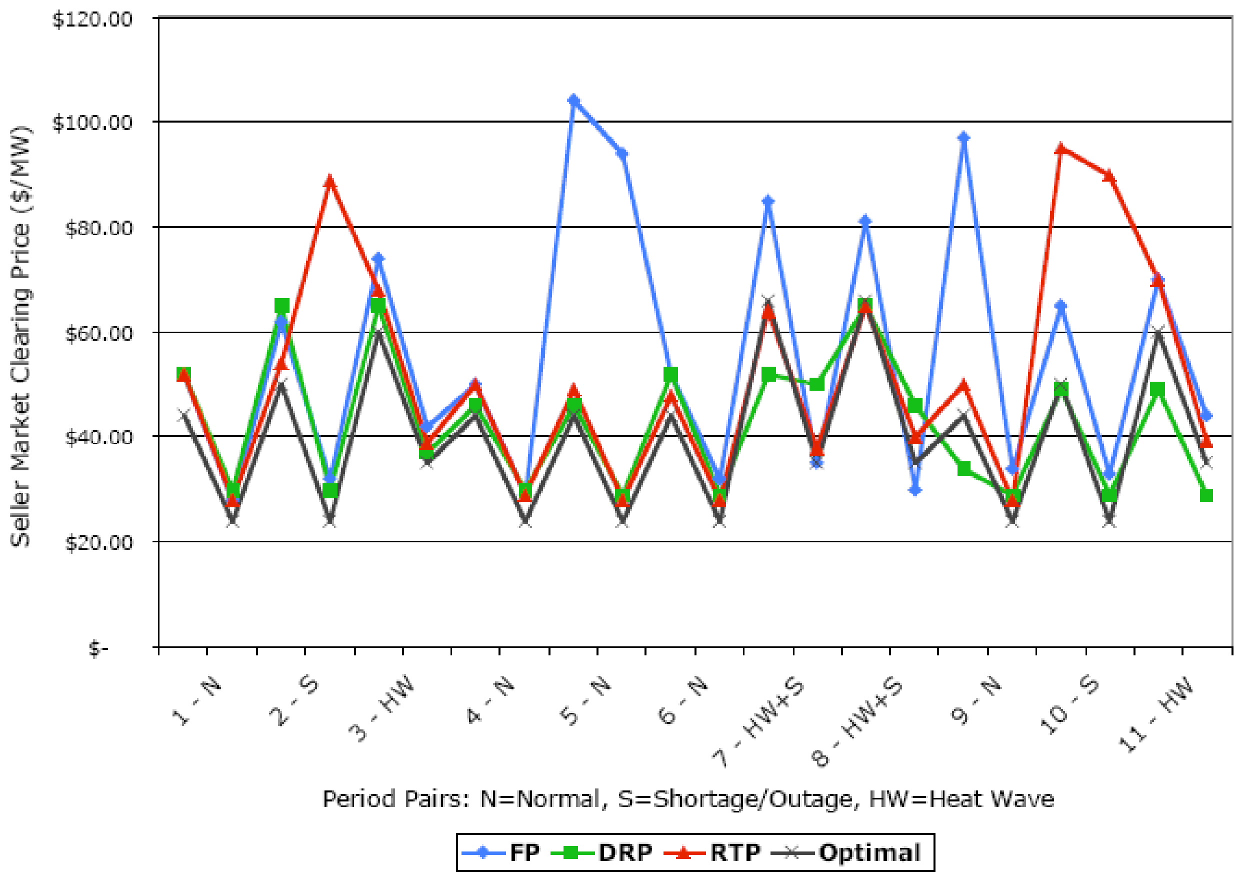
Based on these experimental results the Cornell researchers concluded the following:

> Nevertheless, when pitted against these trained sellers, less sophisticated buyers with fairly simple demand-side mechanisms, representing pre-set demand response programs or real time pricing regimes, were able to mute much of the suppliers' exercise of market power without any regulatory interventions.

The ability of demand response to limit the exercise of market power has strategic implications that go beyond controlling market power. Indeed, it paves the way for nothing less than a paradigm shift in wholesale market design by potentially eliminating the need to pay generators capacity payments, i.e. it can take us to the energy-only market.

Figure 6
Observed Market Prices With and Without Demand-Side Bidding

(Cornell Experiment 2004)



Source: Schuler, Schulze, Zimmerman and Oren, PSERC.

Eliminating Capacity Payments

The process through which demand response can eliminate generator capacity payments might evolve as follows. As increasing amounts of demand response enter the market (at both the wholesale and retail levels), caps on energy prices, which were primarily designed to control market power, will be progressively relaxed. This in turn will stimulate even more demand response as spot prices are allowed to rise higher during times of supply shortage. Also, demand response resources that can be relied on to curtail loads during times of shortage will receive capacity credits, thereby directly displacing new generation. This will progressively reduce the share of planning reserve margins represented by "iron in the ground," thereby increasing the frequency of supply shortages during which the demand response resources will be called and will set market energy prices in excess of the marginal cost of new peaking units. The higher energy prices will progressively reduce the “missing money” problem until it no longer exists. When that end point is reached new generators will no longer need capacity payments to justify market entry and competition among them will drive the price of capacity to zero. Capacity markets will become irrelevant and will cease to exist. We will have reached the “promised land.”

COMMON MISCONCEPTIONS REGARDING ECONOMIC BENEFITS

Reduced Market Price

When demand response providers reduce their loads they also reduce the spot market price. Clearly such price reductions benefit all consumers, even those that did not reduce their loads. However this benefit comes at the expense of the generators as it is a simple transfer of wealth between the two parties. Economists do not treat such transfer payments as economic benefits because actual resource costs are unaffected.

Even if one favors the welfare of consumers over that of generators, the gains to consumers need to be adjusted downward to account for the energy purchased by load-serving entities that is hedged through contracts with generators or power marketers. For example, PJM has estimated that of the energy consumed during a 12 month period in 2006-07, 43 percent was purchased in the day-ahead market and about 9.7 percent in the real-time market.[5] Thus, almost half of the PJM load was hedged.

Finally, such gains to consumers are likely to be short-lived because generators will not build new plants unless they expect to fully recover their investment plus earn at least a competitive, risk-adjusted rate of return. Not only will they not build new plants, they may decide to retire old plants that require capital additions or whose sites have a higher valued alternative use. Based on Andy Ott’s recent statement before this Commission it appears that such retirements were about to occur in PJM.[6]

In evaluating the benefits of its economic demand response program PJM has claimed that the program benefits exceed the costs because the resulting reductions in market prices have saved consumers much more than the payments that PJM has made for the energy it purchased from the DR providers participating in the program. Maybe so, but for the reasons just discussed, that fact alone doesn’t justify continuation of the program in its current form.

PJM is not the only party that has treated income transfers from generators to consumers as an economic benefit. The Brattle Group committed the same error in its study of the impact of

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[5] See *Compensation Threshold Analysis - LMP Impact vs Cost Analysis*, Oct 19, 2007. Available at: http://www.pjm.com/committees/working-groups/dsrwg/dsrwt.html

[6] Ott, Andrew L., *PJM Reliability Pricing Model*, FERC Capacity Market Technical Conference, May, 7, 2008, p 1. Available on the FERC website.

demand response in the Mid-Atlantic States.[7] The Brattle Group, an economic consulting firm, knows better - and indicated so in the body of its report.[8] Nonetheless it chose to highlight the benefit to consumers in the Executive Summary and Conclusions sections of the report but was silent regarding the negative impact on generators.

Reduced Market Price Volatility

It is certainly true that demand response reduces market price volatility, at least in the short-run, and this is good. But as demand response resources are substituted for new generation, price volatility will increase.

Price volatility is not inherently bad if it conveys accurate signals regarding resource cost and availability; however, it does impose risk on both consumers and suppliers. But uncertainty and risk are a fact of life and price volatility is merely the messenger. Any market participant that is unwilling to assume this risk can avoid it through hedging contracts with appropriate counterparties. Reducing price volatility is desirable if it is accomplished through reductions in uncertainty, rather than through mechanisms that suppress or otherwise distort the underlying economic signals.

Improved Power System Reliability

Another half-truth is that demand response improves power system reliability. Although it can in the short-run, once the demand response resource is in place, supply resources will be reduced by just enough to return the system to the desired level of reliability. After all, that's the objective of resource planning – to maintain some target level of reliability. What demand response does bring to the party is a lower cost, more efficient way to achieve that goal and that benefit is captured in the form of avoided capacity and energy costs.

III. COMPARABLE COMPENSATION FOR DEMAND RESPONSE

In its NOPR this Commission raised the question of how demand response providers should be compensated. I addressed this issue last year in my statement submitted in Docket AD07-7-000.[9]

The economically efficient price to pay a DR provider for its load reduction is the locational marginal price at the load's off-take point on the grid, adjusted downward for what the DR provider avoids paying its LSE under its retail tariff. If this saving at retail is ignored the DR

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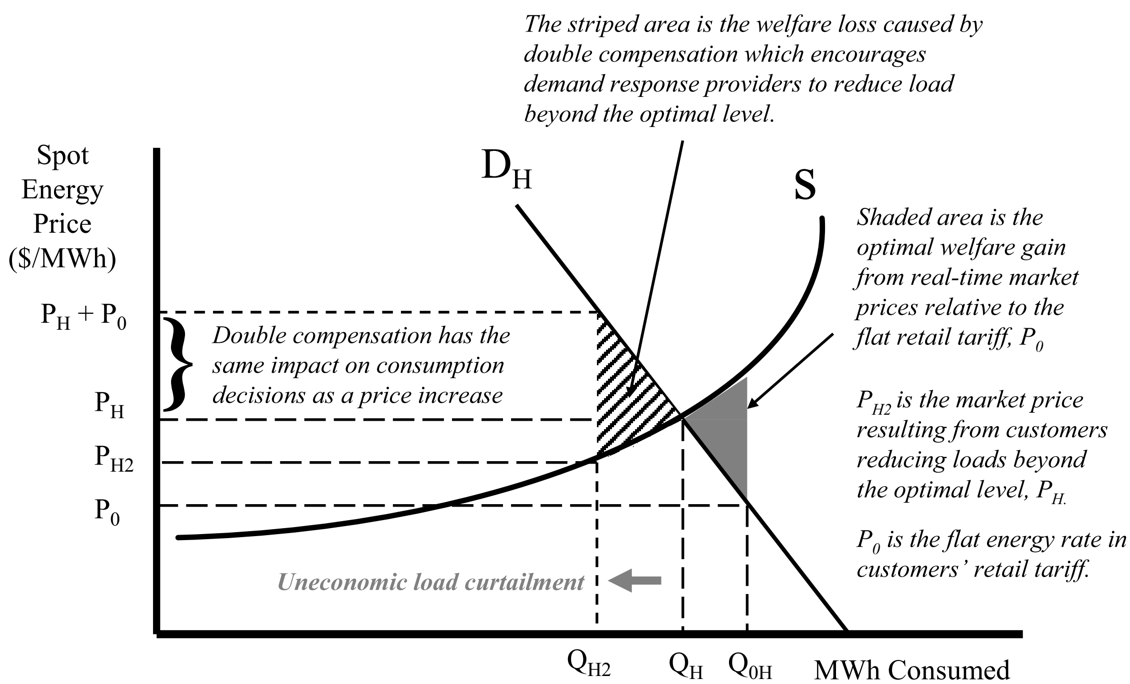
[7] The Brattle Group, *Quantifying Demand Response Benefits In PJM*, Prepared for PJM Interconnection and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007. Available at: http://www.pjm.com/documents/downloads/reports/brattle-report-quantifying-demand-response-benefits-pjm.pdf

[8] Page 20 of the report contains the following statement: "Area bcde represents savings to customers, but it also represents a reduction in producer surplus relative to the less efficient situation in which demand is unresponsive to market signals. As such, this area is not a gain in economic efficiency."

[9] Borlick, Robert L., *Prepared Remarks of Robert L. Borlick, Energy Consultant*, FERC Technical Conference on Competition in Wholesale Markets, Docket No. AD07-7-000, May 8, 2007.

Provider is being subsidized at the expense of other consumers. Even worse, the DR Provider is likely to curtail too much load, causing economic efficiency to be reduced. Essentially generators will be backed off that could have delivered the curtailed energy to the DR provider at an incremental cost that is less than the economic value the DR provider would have derived by consuming the energy. This is demonstrated in Figure 7.

Figure 7
Welfare Loss Produced By Double Compensation of Demand Response Provider



The striped triangle represents the incremental welfare loss that occurs when the demand response provider is paid the market price for its demand reduction and also gets to keep the saving resulting from avoiding payment under the retail tariff for the curtailed energy. This saving at retail effectively increases the DR provider's compensation for reducing load beyond that which it would have received from simply facing the wholesale price. This in turn encourages an additional load reduction, ΔQ equal to $(Q_H - Q_{H2})$, which has a monetary value to the DR Provider approximately equal to the total area under the demand curve between Q_0 and Q_H, i.e., $\alpha^* (P_H + P_H + P_0)^* \Delta Q$, where α is about 1/2. However the total compensation for the load reduction is $(P_{H2} + P_0)^* \Delta Q$ so the DR provider is only too happy to forego that usage.

Now consider the generator whose output is reduced by the load reduction. The incremental energy it was supplying before the load reduction was being produced at an incremental cost equal to $\beta^*(P_H + P_{H2})^* \Delta Q$, where β is also approximately 1/2 (but note that α is unlikely to exactly equal β).

The combined net change in welfare for all parties resulting from the additional load reduction, ΔQ, is:

Net Welfare Change =

(DR Providers) Compensation for load reduction+ avoided retail tariff charge

- foregone value of usage

(Generators) + Reduction in variable costs - reduction in sales revenues

(All LSEs)[10] - Lost LSE revenues from avoided DR Providers' retail tariff charges

(All Customers) + End-Use Customers' bill reductions from lower market price

- DR Provider's compensation charged back to some or all customers.

Quantifying these terms:

Net Welfare Change =

(DR Providers) $P_{H2}*\Delta Q + P_0*\Delta Q – \alpha*(P_0 + 2*P_H)*\Delta Q$

(Generators) $+ P_{H2}*Q_{H2} – P_H*Q_H + \beta*(P_H + P_{H2})*\Delta Q$

(All LSEs) $- P_0*\Delta Q$

(All Customers) $+ P_H*Q_H – P_{H2}*Q_{H2} - P_{H2}*\Delta Q$.

Removing the offsetting transfer payments leaves:

Net Welfare Change = $\beta*(P_H + P_{H2})*\Delta Q – \alpha*(P_H + 2*P_H)*\Delta Q < 0$

[10] The LSEs' reduced outlays for spot market purchases is not included on this line because the LSE will recoup essentially all of these costs from its retail customers through periodic rate adjustments for prudently incurred purchased power. For this reason these savings are included in the first line of "All Customers."

Visual inspection of Figure 7 clearly shows that the first term is smaller than the second term, consequently the net change in economic welfare is negative (a loss). The monetary value of this welfare change is closely approximated by striped area in Figure 7.

My conclusion regarding the uneconomic nature of double compensating DR providers is based on the theory of welfare economics. However, the Cornell experiment described earlier provides empirical evidence corroborating that conclusion. The report cited earlier contains a table summarizing the changes in both Producer's Surplus and Consumers' Surplus, that were observed to occur in the DRP and RTP scenarios, relative to the flat retail tariff scenario, and also relative to generator offers strictly limited to their true marginal costs. The impacts on Producers' Surplus and Consumers' Surplus, in the absence of demand response, were also summarized in that table, which is reproduced below as Table 1.

As shown there, consumers' benefits were higher under DRP than under RTP while the opposite was true for the generators. But *total economic welfare* decreased under the DRP program while it increased under the RTP program, indicating that real-time pricing was economically efficient but DRP pricing was not. The DRP scenario simulated the NYISO's EDR program, including the double compensation feature. Thus, in that scenario load-reducing customers were over-compensated by allowing them to keep the savings from avoiding payment under the flat tariff for their foregone energy.

Table 1
Impacts of Demand Response on Consumers' and Producers' Surplus from Fixed Price Regime Levels as Percent of Wholesale Market Revenue

	Adjusted CS Difference from Fixed Price	PS Difference from Fixed Price	TS Difference from Fixed Price
	Experiment 1 (November, 2003)		
Demand Reduction Program (DRP)	8.97%	-12.71%	-3.73%
Real Time Pricing (RTP)	7.22%	-4.57%	2.65%
Socially Optimal (SO)	31.12%	-21.88%	9.25%
	Experiment 2 (April, 2004)		
Demand Reduction Program (DRP)	18.67%	-22.27%	-3.60%
Real Time Pricing (RTP)	10.79%	-9.38%	1.41%
Socially Optimal (SO)	27.55%	-23.25%	4.30%
	Combined Experiments		
Demand Reduction Program (DRP)	13.86%	-17.52%	-3.66%
Real Time Pricing (RTP)	9.02%	-6.99%	2.02%
Socially Optimal (SO)	29.32%	-22.57%	6.75%

Source: Schuler, Schulze, Zimmerman and Oren, PSERC.

IV. REACHING THE "PROMISED LAND"

So what's so great about an energy-only market? A lot! Eliminating the need for capacity payments brings substantial gains in economic efficiency. In addition, it empowers consumers to buy only the amount of power system "reliability" they want at the lowest cost.[11]

Because the focus of this technical conference is not to delve into the advantages of the energy-only market I will only briefly summarize those advantages. Readers interested in this topic can read two white papers – one written by Professor William Hogan and the other written by the Midwest ISO staff with my assistance and that of John Chandley of LECG.[12]

ADVANTAGES OF THE ENERGY-ONLY MARKET

Paying generators only for the electric energy they deliver provides the optimum economic incentive for them to be available when they are needed. In contrast, capacity payments blunt this incentive, a fact that is beginning to be fully appreciated. Some capacity markets, such as ISO-NE's, attempt to compensate for this by concentrating capacity payments in the hours of peak demand. Taken to the limit the ISO-NE methodology would morph into the energy-only market.

Exposing consumers to the full spot price, while simultaneously liberating them from paying a capacity charge, allows them to base their consumption decisions solely on the value of the resources required in the short-run to deliver the energy they consume. This provides each consumer with the optimal economic incentive to consume and to conserve. Furthermore, when generation resources are scarce some means is needed to ration the limited supply among consumers. The energy-only market, in conjunction with demand response, allows the consumers to collectively decide how much electricity each gets.

Finally, spot prices in the energy-only market provide the optimal incentives to make the right investments in new plant and equipment to provide for future consumption. This includes allowing market forces to determine the degree of power system reliability that is economically justified, thereby obviating the need for administratively determined reliability criteria (such as the ubiquitous "one-day-in-ten-year" LOLE standard) that all consumers must pay for regardless of their individual needs or preferences.

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[11] If all consumers have the ability to adjust their usage in response to market price signals the concept of power system reliability loses meaning because nobody would get involuntarily curtailed and power system reliability would cease to be a "public good." However, power system security, i.e., preventing cascading failures that shut down large portions of the system, would remain a public good and would still need to be enforced through mandatory standards governing operating reserves requirements, which all consumers would still pay for.

[12] Hogan, William W., *On an "Energy Only" Electricity Market Design for Resource Adequacy*, John F. Kennedy School of Government, Harvard University, September 23, 2005. Available at: http://www.whogan.com

Midwest Independent System Operator, *AN ENERGY-ONLY MARKET FOR RESOURCE ADEQUACY IN THE MIDWEST ISO REGION*, November 23, 2005. Available at: http://stoft.com/metaPage/lib/MISO-2005-11-emergy-only-market.pdf.

GETTING FROM HERE TO THERE

Although demand response is a necessary ingredient to achieving an energy-only market, it is not sufficient by itself. The other ingredients are:

- Allowing demand response resources to substitute for generation in the planning reserves mandated to assure resource adequacy
- Allowing demand response to set spot energy market prices during hours of supply adequacy
- Relaxing price caps on energy market prices until they reach the value of lost load (VOLL)[13]
- Adopting capacity market mechanisms that do not confiscate ex-post the rents that generators earn during times of scarcity.

This Commission is well on its way to adopting the first two conditions and hopefully will adopt the third when assured that demand response is sufficient to control generator market power. The last point deserves further comment.

As described earlier, as demand response resources increasingly displace generation in planning reserve margins, there will be more hours of supply scarcity during which the demand-side will be setting market prices. During those hours generators will earn scarcity rents that make them less reliant on capacity payments. But this evolutionary process will only proceed if generators are allowed to keep those scarcity rents. All market designs do not provide for this.

PJM's capacity construct (RPM) allows generators to keep scarcity rents and PJM prospectively adjusts its capacity demand curve downward to account for these rents. In contrast, ISO-New England's capacity mechanism retrospectively confiscates any scarcity rents that would be earned by a proxy generating unit.[14] Thus, the PJM capacity market could conceivably evolve to the energy-only end state whereas the ISO-NE market cannot, at least not without design modification.

Five years ago I conducted an analysis that estimated the equilibrium conditions that would be needed for an energy-only market to endogenously produce power system reliability similar to what we enjoy today. The results were presented at an IAEE conference and a copy of the presentation is included in Appendix B.

Figure 8.summarizes the results I obtained.

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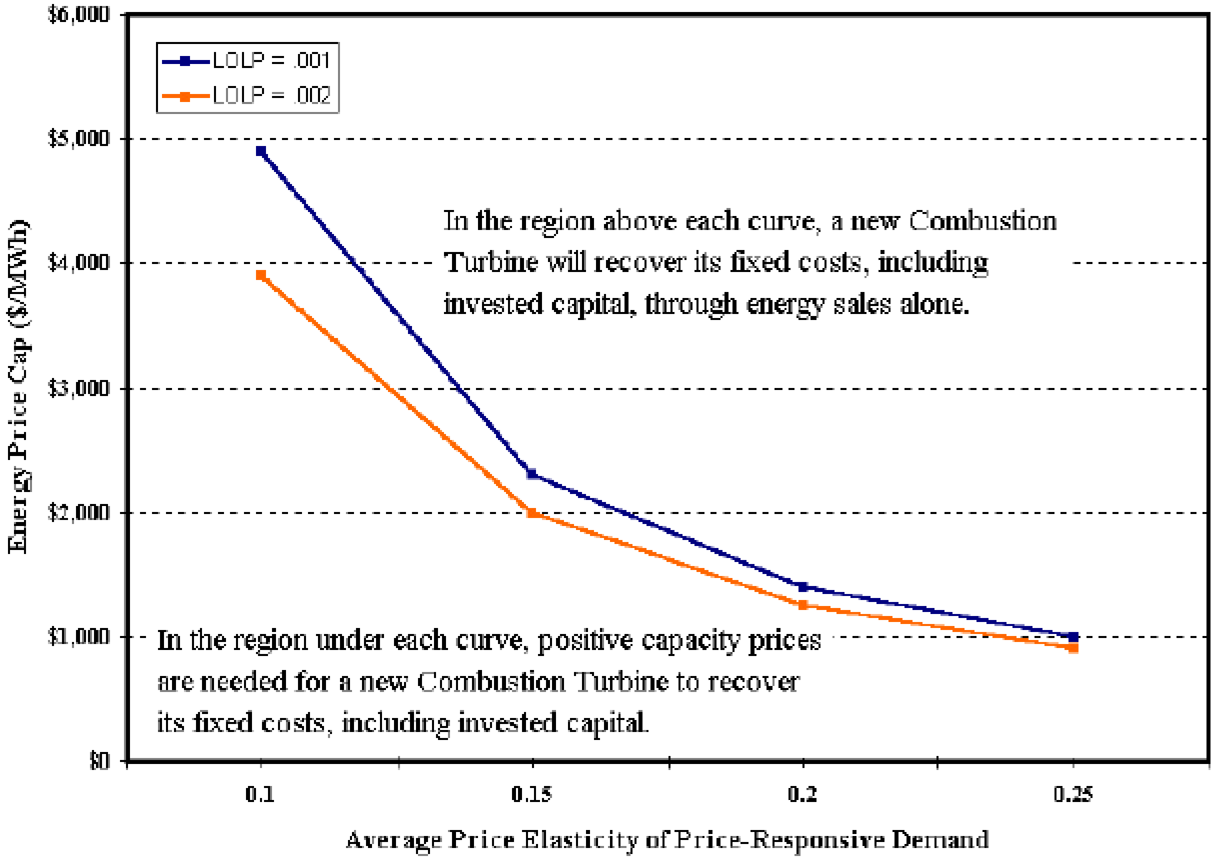
[13] Caps on generator offer prices need not be raised much above the current $1000/MWh level because during hours of scarcity prices would be set by the demand-side and generators would be price-takers. However, price caps on demand response offers must go substantially higher.

[14] Even though the proxy unit is an inefficient peaker with a heat rate of 22,000 BTU/KWh, it will still create a "missing money" problem and prevent capacity prices from reaching zero.

Figure 8
Minimum Energy Price Cap Required to Attract Entry of New Combustion Turbines



Admittedly these estimates are only suggestive because they were produced with a relatively simple EXCEL model that I used to simulate a generic power market. Even so, the results are encouraging.

THE KEY ROLE OF THE FERC

This Commission's future decisions regarding wholesale market design are critical to bringing about a smooth, evolutionary transition to the energy-only market without risking the exercise of generator market power or jeopardizing power system reliability. It can do this by adopting a "backstop" resource adequacy requirement which eventually will not become a nonbinding constraint.

APPENDIX A

ESTIMATING THE MONETARY EQUIVALENT VALUE OF FORGONE ELECTRICITY CONSUMPTION

This appendix demonstrates how the value of foregone electricity consumption can be monetized. This methodology applies equally to load reductions produced in response to higher prices and to loads that are interrupted in response to command-control instructions. In either case all one needs is an estimate of the price elasticity of the consumer's demand curve and the amount of the load reduction.

Figure A1 graphically illustrates the consumer's surplus when confronted with price P. We are interested in how the consumer's surplus changes in response to a change in the quantity consumed.

Figure A1
Net Monetary Value of Electricity Usage

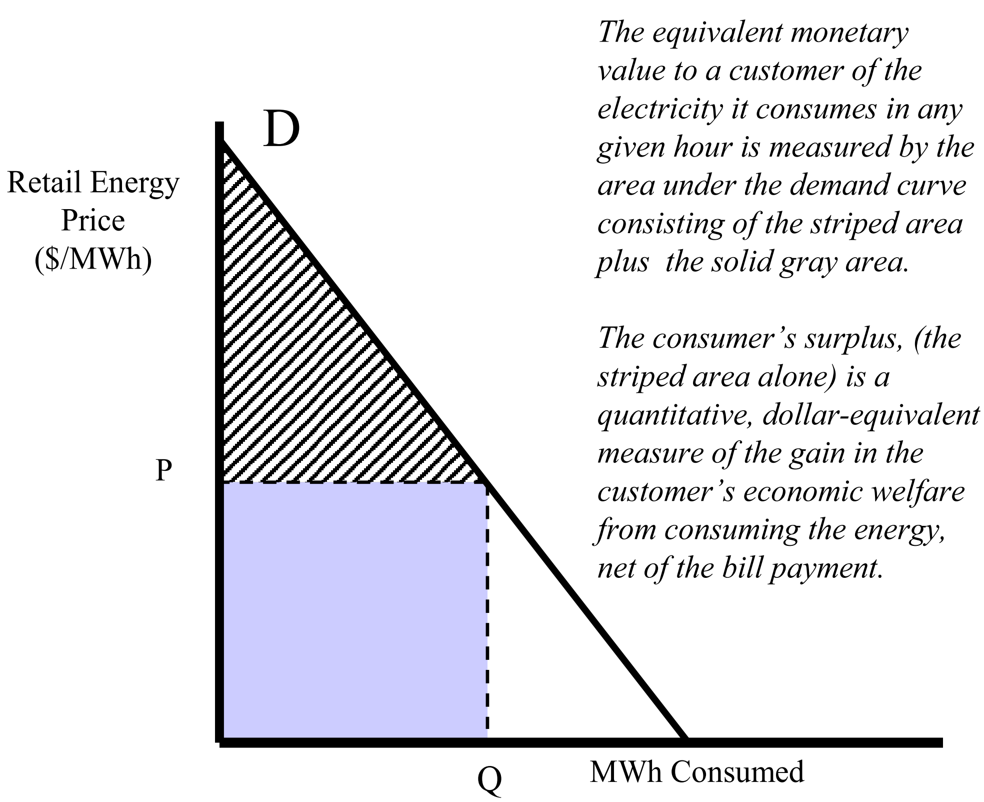
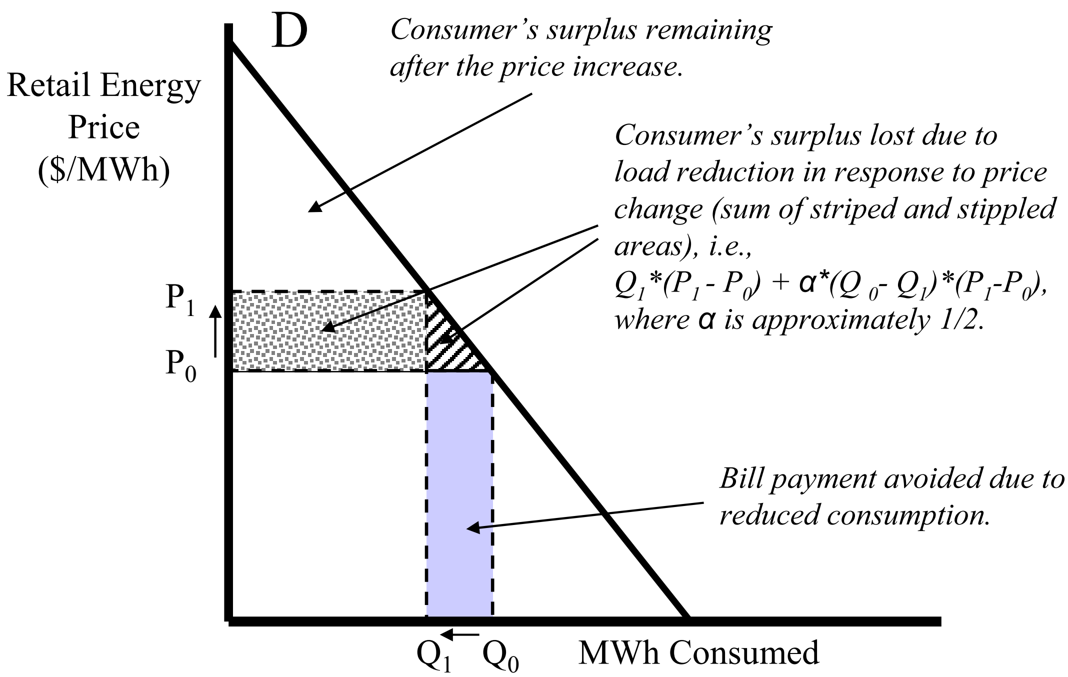


Figure A2 illustrates the reduction in consumer's surplus when energy usage is curtailed in response to a price increase.

Figure A2
Loss in Monetary Value from Reduced Electricity Usage



To quantify the customer's monetary loss from consuming less we need to estimate the size of the striped and stippled areas. Clearly, the stippled area is equal to $Q_1*(P_1-P_0)$. The striped area is a bit harder to quantify but we can do that if we know the customer's average price elasticity of demand, ε, over the region of the demand curve between Q_0 and Q_1.

If we assume that price elasticity is constant over that range, price and quantity are given by:

(A1) $$Q = Q_0*(P_o/P)^{\varepsilon}$$

The striped plus solid shaded areas under the demand curve between Q_0 to Q_1 can be quantified by integrating equation (A1) from Q_0 to Q_1:

(A2) $$\Delta \text{ Area} = \int P(Q)\, dQ$$

(A3) $$\Delta \text{ Area} = P_0*(Q_0)^{1/\varepsilon}*[Q_1^{(1-1/\varepsilon\}} - Q_0^{(1-1/\varepsilon\}}]*(1-1/\varepsilon)^{-1}$$

Adding in the stippled rectangular area and subtracting out the shaded rectangular area yields the total change in consumer's surplus:

(A4) $$\Delta CS = P_0*(Q_0)^{1/\varepsilon} * [Q_1^{(1-1/\varepsilon\}} - Q_0^{(1-1/\varepsilon\}}]*(1-1/\varepsilon)^{-1} + P_0*(Q_0 - Q_1) - Q_1*(P_1 - P_0)$$

(A5) $$\Delta CS = P_0*(Q_0)^{1/\varepsilon} * [Q_1^{(1-1/\varepsilon\}} - Q_0^{(1-1/\varepsilon\}}]*(1-1/\varepsilon)^{-1} + P_0*Q_0 - P_0*(Q_0/Q_1)^{1/\varepsilon}$$

Although equation (A5) is a bit messy its application is straightforward. Because it is expressed in terms of energy use before and after curtailment, and the price paid by the consumer *before* curtailment, it can be used to value changes in welfare derived from either price-responsive demand or interruptible load.

APPENDIX B

Mandatory Reserve Margins
Good Idea or Not?

by
Robert L. Borlick

26th IAEE International Conference
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Overview

The Issue

- Every power system requires sufficient reserve generating capacity to provide reliable service.
- One way to provide such reserve capacity is by directly imposing a mandatory generation reserve margin (MRM).
- Another way is for free market forces to provide developers with sufficient incentives to build.

Which is better?

2

Overview

Current Practice

- Deregulated North American power markets have almost universally adopted the MRM approach.
- The only exception is California, which initially adopted a market-based approach but is now moving to toward MRM.
- The recent FERC NOPR on Standard Market Design (SMD) includes a "resource adequacy" requirement that attempts to balance generation, demand reduction and transmission capacity.

3

Overview

Drawbacks of the MRM Approach

- The MRM approach exogenously imposes a level of reliability that does not maximize net benefits to electricity customers.
- Also, it is unfair because it forces all customers to accept the same level of reliability and to pay for it whether they want it or not.
- In other markets customers' choices determine prices and product quality - not so with MRM.

4

Overview

Drawbacks of the Market-Based Approach

- To be effective the market-based approach requires significant amounts of price-responsive demand (PRD), which doesn't exist today.
- Without PRD the market-based approach produces:
  - high electric price volatility
  - potentially unacceptably low reliability
  - a weak deterrent to generator market power.
- California clearly demonstrated this in 2000-01.

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Overview

Importance of Price-Responsive Demand

- When PRD is combined with either approach the combination can produce:
  - the optimum level of system reliability
  - customer choice regarding *their* service reliability
  - a more equitable allocation of costs.
- However, the MRM approach discourages PRD development by suppressing energy price volatility.

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Some Basic Concepts

Energy Prices With No Demand Elasticity

7

Some Basic Concepts

Energy Prices Must Be Capped

- There is no limit to how high energy prices can spike when demand exceeds supply.
- A price cap will deter the exercise of market power by making capacity withholding less profitable.
- Bid evaluation software has practical limits on how large a number it can handle; exceeding the limits can crash the system.
- The above reasons remain even with PRD.

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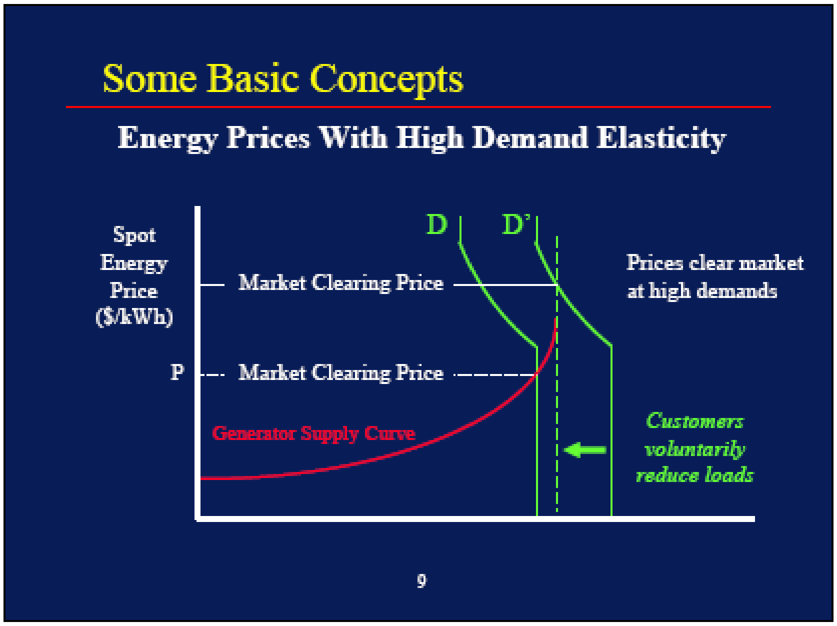
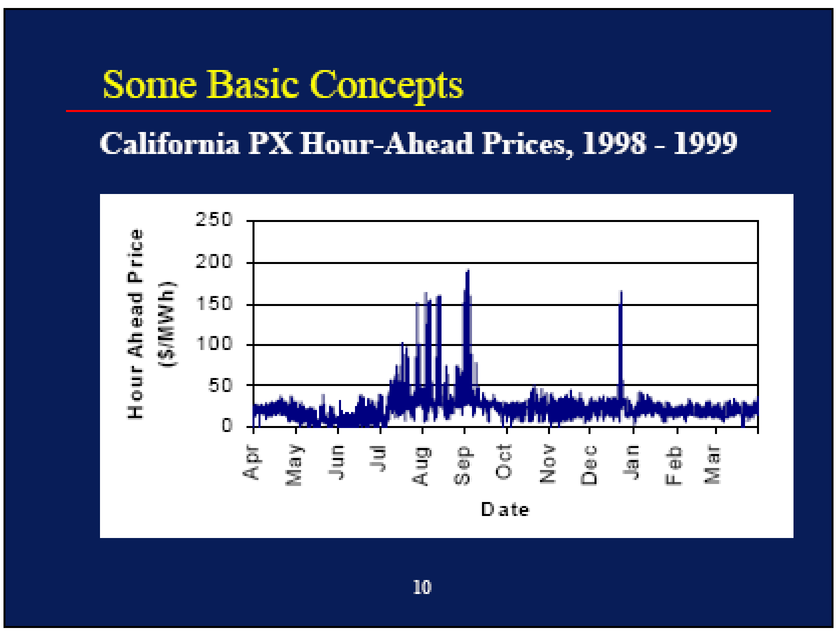
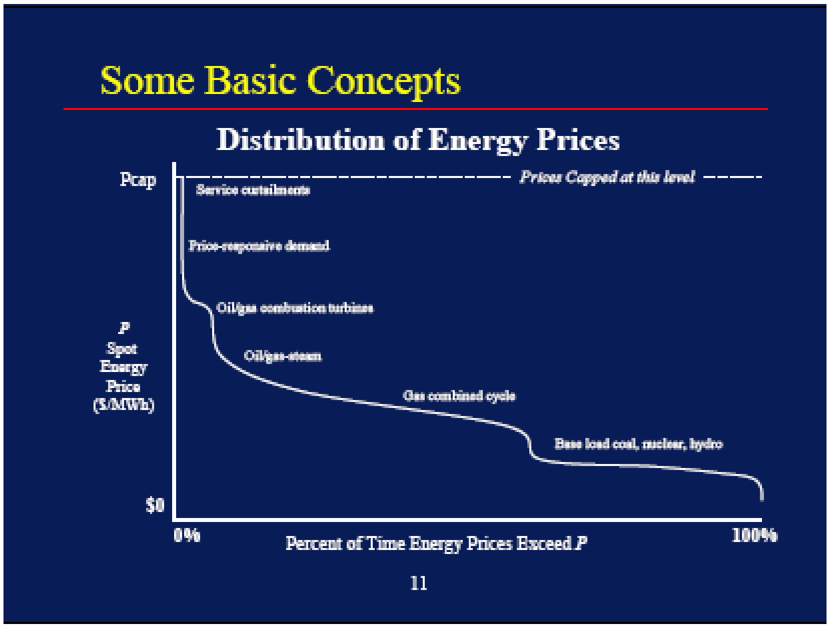
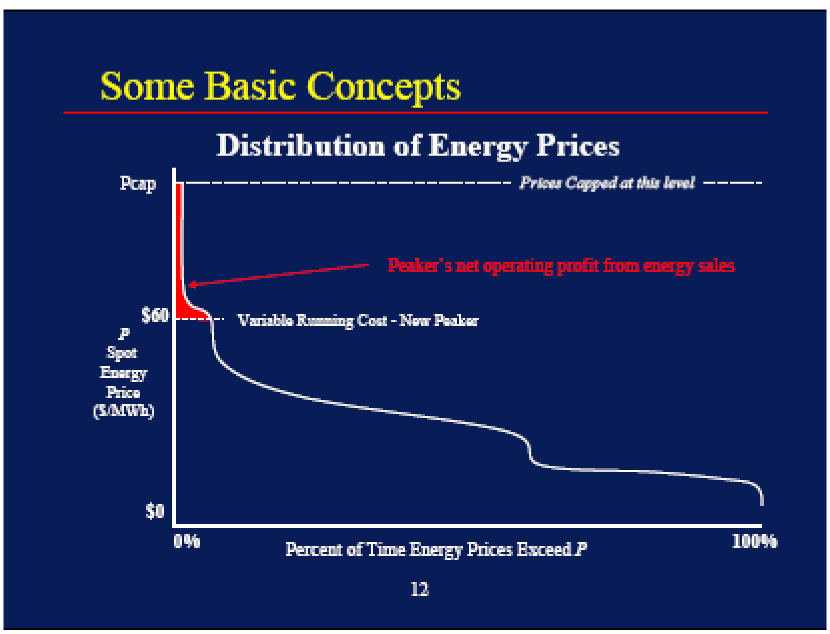

Some Basic Concepts
Energy Prices With High Demand Elasticity
Spot Energy Price ($/kWh)
D
D'
Market Clearing Price
Prices clear market at high demands
P
Market Clearing Price
Generator Supply Curve
Customers voluntarily reduce loads
9

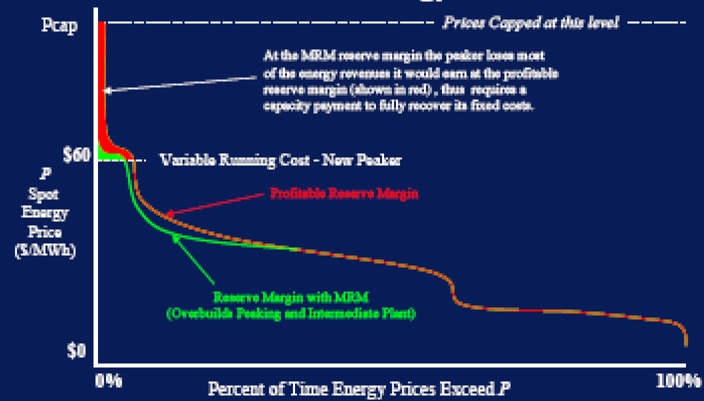

Some Basic Concepts
California PX Hour-Ahead Prices, 1998 - 1999
Hour Ahead Price ($/MWh)
250
200
150
100
50
0
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Feb
Mar
Date
10


Some Basic Concepts
Distribution of Energy Prices
Pcap
Prices Capped at this level
Service curtailments
Price-responsive demand
Oil/gas combustion turbines
Oil/gas-steam
Gas combined cycle
Base load coal, nuclear, hydro
P
Spot
Energy
Price
($/MWh)
$0
0%
Percent of Time Energy Prices Exceed P
100%
11


Some Basic Concepts
Distribution of Energy Prices
Pcap
Prices Capped at this level
Peaker's net operating profit from energy sales
$60
Variable Running Cost - New Peaker
P
Spot
Energy
Price
($/MWh)
$0
0%
Percent of Time Energy Prices Exceed P
100%
12

Some Basic Concepts

Distribution of Energy Prices



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Power Supply Reliability

Power Supply Reliability - No MRM

- Developers will only build generation up to the point where they expect a new peaker to just recover its fixed costs, including a risk-adjusted return on invested capital.
- A cap on energy prices will affect a peaker's fixed cost recovery prospects.
- Thus in an energy-only market the price cap will solely determine power system reliability.

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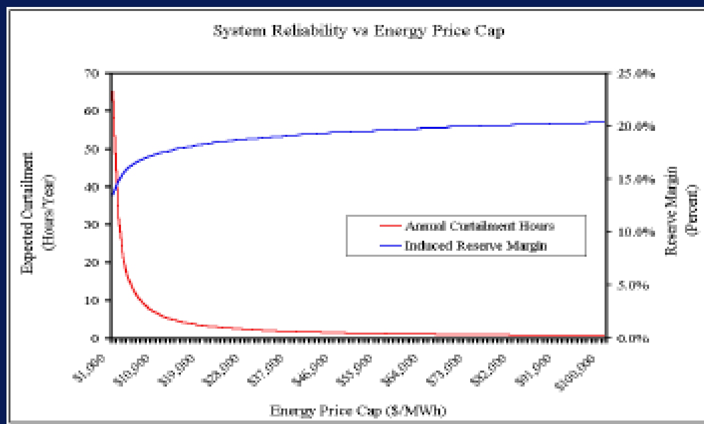
Power Supply Reliability



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Power Supply Reliability

Power Supply Reliability - No MRM

- The FERC recently proposed a $1000/MWh price cap (primarily to deter market power abuses).
- A new peaker requires about $55,000/MW-Yr., on average, to fully recover its fixed costs.
- Thus, energy prices must reach the cap (and load curtailed) approximately 65 hours per year
  - Shortage Hours ≈ ($55,000)/.9*($1000-$60).
- This level of reliability is clearly too low.

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Power Supply Reliability

Power Supply Reliability - No MRM

- If the price cap is raised to $60,000/MWh the expected number of outage hours drop to about 1 hour per year - close to the "one-day-in-ten-years" standard adopted in North America.
- This reliability standard is too high; few end uses are worth serving at $60,000/MWh.
- Also, such a high cap creates high price volatility and does not suppress generator market power.

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Power Supply Reliability

Power Supply Reliability - with MRM

- Because the MRM directly determines the reserve margin it overrides low price cap disincentives.
- Still, a properly set price cap can achieve the same reserve margin without a MRM to produce:
  - the same reliability and total customer cost
  - more equitable distribution of costs
  - but much more volatile energy prices.

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The Impact of PRD

Little Price-Responsive Demand Exists Today

- In North American power markets electricity demand is virtually inelastic in real time.
  - This is not a “law of nature,” it is the result of the way we designed our power systems
  - Most customers face fixed tariffs designed to recover the utility’s costs averaged over one- or two-month billing cycles.
- Today we have the technology to change this.

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The Impact of PRD

Benefits of Price-Responsive Demand

- The economically efficient level of supply reliability can be closely approximated.
- Individual customers can choose the levels of reliability they are willing to pay for.
- Generator’s market power can be deterred and price volatility dampened without employing restrictively low price caps.

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The Impact of PRD

Hypothetical Example

- Target reliability for non-PRD loads is one-day-in-10 years (equivalent to 18 % reserve margin).
- The average equivalent forced outage rate for generators in this power market is 10%.
- Price cap is set at $2,500/MWh to approximate the value of lost load (VOLL) for residential customers.
- First-year carrying cost of a CT is $55/KW-Yr.

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The Impact of PRD

Hypothetical Example

- Industrial and commercial customers offer total PRD capacity equal to 30% of system peak.
- PRD begins to respond at $150/MWh with average demand elasticity of -.15.
- PRD counts as part of the reserve requirement.

Note: the PRD assumptions used here approximate what Georgia Power Company's RTP Program has achieved.

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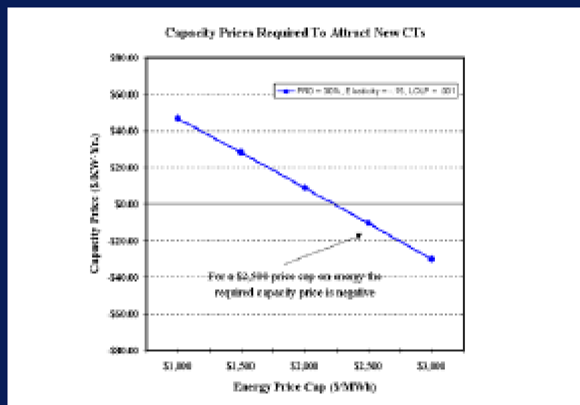
The Impact of PRD



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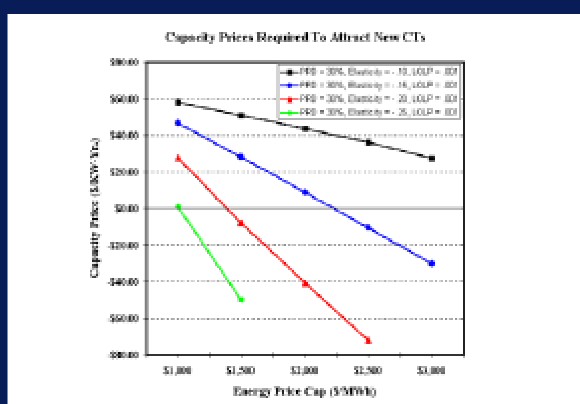
The Impact of PRD



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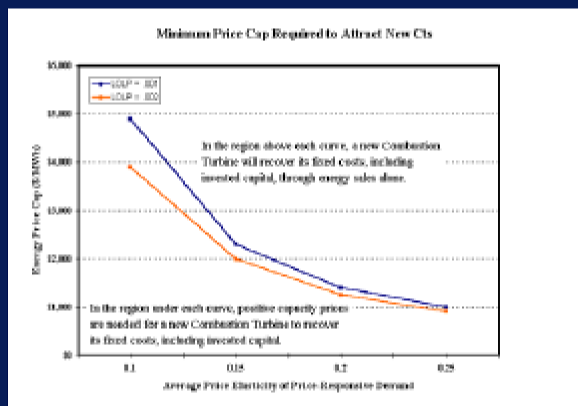
The Impact of PRD



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Interaction with Operating Reserve

Operating Reserve Requirement

- In the example PRD provides about 10 % of the 18% reserve requirement when the price cap binds.
- But the 10% FOR combined with a typical 7% operating reserve requirement, means that, on average, generation capacity can only serve about 90% of peak load - the balance is served by PRD.
- Thus, the system's operating reserve will first be depleted before energy prices rise enough to induce a significant PRD response.

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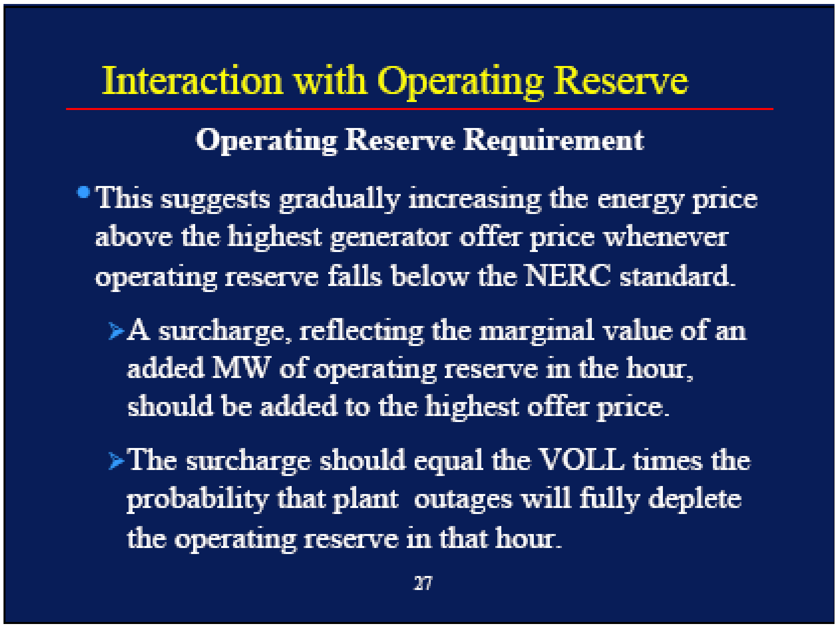
Interaction with Operating Reserve
Operating Reserve Requirement
This suggests gradually increasing the energy price above the highest generator offer price whenever operating reserve falls below the NERC standard.
A surcharge, reflecting the marginal value of an added MW of operating reserve in the hour, should be added to the highest offer price.
The surcharge should equal the VOLL times the probability that plant outages will fully deplete the operating reserve in that hour.
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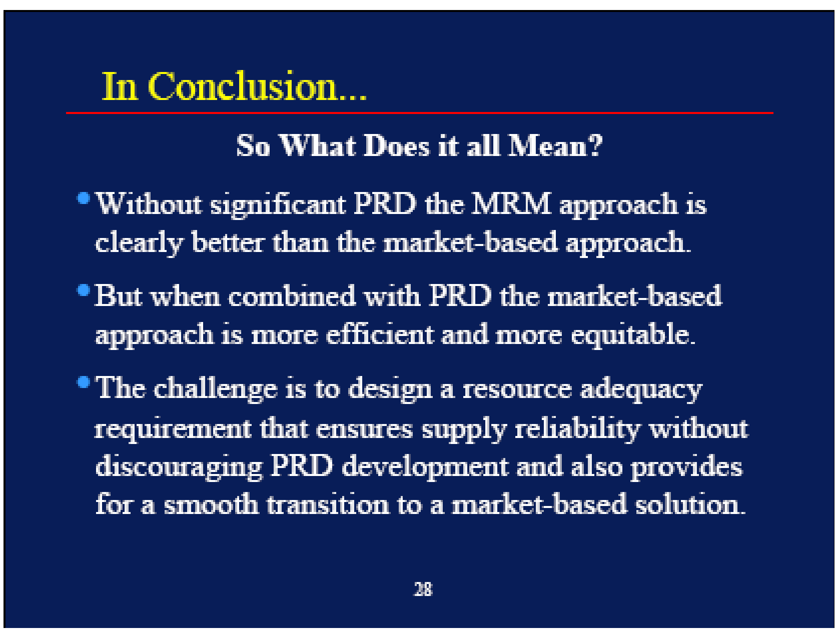
In Conclusion…
So What Does it all Mean?
Without significant PRD the MRM approach is clearly better than the market-based approach.
But when combined with PRD the market-based approach is more efficient and more equitable.
The challenge is to design a resource adequacy requirement that ensures supply reliability without discouraging PRD development and also provides for a smooth transition to a market-based solution.
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In Conclusion…

So What Does it all Mean?

- A modified form of the MRM can be adopted:
  - Set the required generation reserve margin equal to the MRM without PRD *less* the amount of PRD response expected at the energy price cap
  - Hopefully the reserve requirement will not bind.
- This approach allows PRD to compete on equal terms with new generating plant, thus promotes its development without subsidies.

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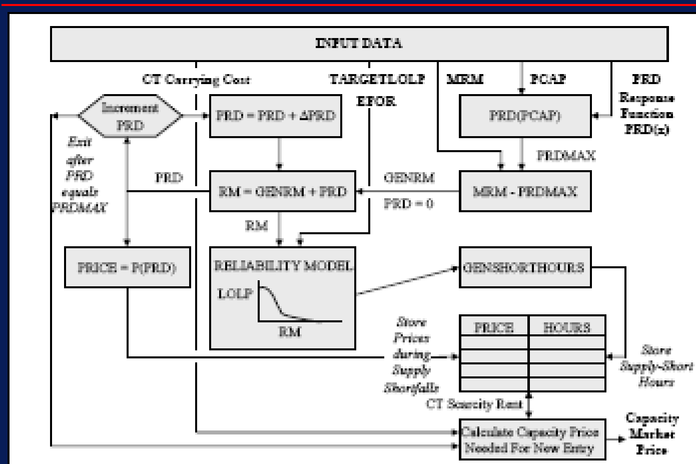
APPENDIX - Model Description



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