The Future of Demand Response in RTO Energy Markets: Midwest ISO Studies on Resource Adequacy

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ABSTRACT

Regional Transmission Organizations (RTOs) are redefining their roles in assuring that there will be adequate generation and demand-side resources to meet future electricity demand. The northeastern RTOs have created mandatory capacity markets, require forward purchases of installed capacity, and in the case of PJM and New England are proposing significant changes in resource adequacy policies. The Midwest Independent Transmission System Operator (Midwest ISO) is proposing an alternative that would create incentives for resource development through shortage pricing in short-term energy markets. Midwest ISO's market based approach will create new opportunities for demand response.

This paper will review different RTO resource adequacy plans and their implications for demand response. RTOs will have a critical impact on the development of demand response programs. RTO administrative decisions to purchase capacity, potentially years in advance of when it might be needed, can dampen short-term price volatility and thereby reduce demand response and the incentive to make investments that would facilitate it.

This paper describes a Midwest ISO program of market analysis and design studies on alternative approaches to ensuring resource adequacy. These studies examine options designed to facilitate the emergence of efficient markets with active demand participation. The paper addresses available conclusions and quantitative results, Midwest ISO resource adequacy policies, and their implications for demand response. The Midwest ISO will propose a permanent resource adequacy plan and related changes in its regional transmission tariff in June 2006.

Introduction

From 2001 through 2004, U.S. utilities and independent power producers added 180,000 MW of new generating capacity. Planned capacity additions to be completed in the period 2005 through 2014, however, total less than 80,000 MW (NERC 2005). As the generation surplus that developed in the first part of this decade diminishes, policy makers face critical choices about how to ensure that adequate resources will continue to be available. For much of the nation, these choices are playing out in a series of FERC proceedings related to RTO resource adequacy plans. FERC's decisions will impact reliability, consumer prices, and billions of dollars of investment. And, they could greatly expand or limit the role of demand response.

Requirements for new generating capacity over the coming decade could be reduced if a growing number of consumers have the capability and opportunity to respond to day-ahead and real-time price signals. Illustrative analyses of the potential of demand response (Borenstein 2005; Centolella and Parmalee 1997; DOE 2003; ICF 2002; and Neenan et al. 2005) and integrated resource planning studies (Faraqui and George 2002; NPCC 2005; and Violette et al. 2006) have projected significant economic benefits associated with greater reliance on price responsive demand. Additionally, laboratory studies (Rassenti et al. 2002) and market simulations (Boorenstein and Bushnell 1997) have shown that demand response can eliminate or significantly reduce the opportunity for suppliers to exercise market power. While selected demand response programs, such as the Georgia Power Real Time Pricing Program, have produced significant reductions in peak electricity consumption, the reductions and benefits reported for most programs have been more limited (Barbose et al. 2004; NYISO 2004; PJM Interconnection 2004; and RLW Analytics and Neenan Associates 2004). The potential of demand response to significantly reduce the cost of electric power has remained to a significant degree unrealized in the transition to more competitive power markets (Centolella 1998, DOE 2006).

While several factors may contribute to individual programs not achieving their potential, an underlying limitation on demand response has been that U.S. electricity markets are managed so as to ensure that they will remain in surplus and exhibit limited price volatility. And, where shortages have occurred, retail prices often have not reflected shortage conditions. Public policy has intervened in power markets to promote capacity development on the assumption that demand response would be limited. However, price responsive demand is a short term response to volatility in short term prices. Policies which ensure that substantial reserve margins of generating capacity will be built (or remain on line) suppress price volatility in short-term energy markets, turning the assumption of limited demand response into a self-fulfilling prophesy.

Whether policy makers approach ensuring resource adequacy through installed capacity requirements or alternatively by structuring markets such that price signals reflect shortage conditions will have a profound impact on the development of demand response over the coming decade. The Midwest ISO is preparing a resource adequacy plan that will seek to promote long-term resource adequacy by creating the correct price signals and incentives in its day-ahead and real-time energy and operating reserve markets. It would provide, subject to regulatory and system security limitations, Load Serving Entities (LSEs) and consumers a choice over the extent to which they cover their peak energy requirements through forward contracts or mange their energy use in response to short-term prices. While we anticipate that most loads would hedge price risks through voluntary forward contracts, the Midwest ISO does not currently contemplate requiring its member companies to make forward capacity purchases. In this respect, the Midwest ISO proposal is comparable to the so called “energy only” markets that are found in Australia, Alberta, New Zealand, parts of Europe, and ERCOT. By contrast, the New York ISO, ISO New England, and the PJM Interconnect, which evolved out of tight power pools with pre-existing capacity requirements, have implemented capacity markets and required LSEs to own or contract in advance for capacity to meet specified reserve margin requirements.

This paper provides background on the approaches being pursued by the RTOs in the Northeastern states and examines the apparent failure of energy prices to reflect geographic differences in capacity availability within these markets. It describes the key design elements of the Midwest ISO’s resource adequacy proposal. Finally, it outlines a research program that the Midwest ISO has undertaken and summarizes currently available results from that research.

Resource Adequacy Mechanisms: Development of Capacity Requirements

The Northeast Blackout of 1965 led to the formation of power pools in New England, New York, and the PJM region. These pools improved reliability by allowing members to share loads and resources and also instituted pool-wide installed capacity requirements. Prior to open access transmission service and retail choice, resource adequacy also was addressed in Integrated Resource Planning (IRP) and related state regulatory proceedings.

With the breakdown of the vertically integrated utility model in most Northeastern states, the regional power pools, which developed into RTOs, assumed full responsibility for implementing installed capacity requirements.[1] To implement these requirements, the Northeast RTOs have pursued different variations of Installed Capacity (ICAP) markets. These markets allow pool members to trade capacity credits such that, if one LSE has more than it needs, it can sell capacity credits to another LSE in the pool that is short. These capacity credits are simply a means of determining whether the LSE has met its capacity requirement. They are not call options. The purchaser has no right to capacity or energy at a specific strike price.

RTO Capacity Markets: Complex Administrative Interventions

ICAP markets, such as those in New York and the PJM region, are the deployment mechanism for meeting Installed Reserve Margin (IRM) requirements. IRM requirements are set by the RTO a year in advance and represent the amount of capacity that will be needed to meet a specified reserve margin (e.g. 118% of forecasted peak demand in New York and 115% in PJM). The RTO assigns each LSE in the pool a specific capacity responsibility based on its historical or forecasted contribution to pool-wide coincident peak load. LSEs are charged deficiency penalties to the extent they fail to meet these obligations. Generators receive credit for a portion of their installed capacity, which has been administratively derated to reflect each unit's historical forced outage rate. To qualify for ICAP payments, generators also may be required to offer their resources into the Day-Ahead energy market, coordinate planned outages with the pool, and condition their exports to other areas such that they are recallable to serve pool loads.

As these RTOs identified additional problems with their ICAP mechanisms and sought to make corrections, their capacity markets have become increasingly complex. When pool-wide capacity markets proved inadequate, the RTOs have added locational requirements. For example, the New York ISO has additional installed capacity requirements for transmission constrained areas around New York City and on Long Island. And, the RTOs became concerned that price signals based on IRM quantities were either high when the requirement had not yet been met or zero when there was more than enough installed capacity. This led the New York ISO to create an administratively determined demand curve in its installed capacity market.

After 20 months of near zero prices, the ISO – New England ICAP market cleared at $20,000 per kW-month in January, 2000. When that occurred, ISO-New England decided that there was insufficient competition in its ICAP market and settled the market at a zero price, effectively abandoning ICAP as a way to promote resource adequacy. As interim measures, ISO-New England created a forward reserve market and began signing Reliability Must-Run (RMR) contracts to keep on line generators in Boston and Southwest Connecticut where capacity was needed. In 2005, its RMR contracts accounted for more than 10% of the total capacity in the New England Pool. ISO-New England and most of its stakeholders recently reached a proposed

[1] It is worth noting that this evolution is a departure from the traditional authority of the states over generating capacity. RTOs are federally regulated transmission system and wholesale power market operators. The authority of the Federal Energy Regulatory Commission (FERC) to require LSEs to purchase or maintain generating capacity is currently unclear. The Federal Power Act grants FERC jurisdiction only over the transmission and wholesale sale of power in interstate commerce.

settlement in a contentious FERC proceeding, agreeing to establish a one-year in advance Forward Capacity Market (ISO-New England 2006).

To address concerns about deliverability and volatility in its capacity market, PJM has proposed a new approach to capacity markets called a Reliability Pricing Model (RPM). The key components of the RPM proposal include: a four-year forward LSE obligation to purchase capacity resources; additional forward auctions to permit LSEs to adjust their capacity positions, specific locational capacity requirements, and the use of an administratively determined downward-sloping demand curve for resources to reduce volatility in the capacity market.

RTO Capacity Markets: A Substitute for Efficient Pricing

Electricity is a unique commodity. Supply and demand must be kept continuously in balance. Power flows are managed through generator dispatch or demand management. And, the marginal cost of power can change greatly over brief time intervals and between locations.

In an efficient market, differences in the cost and value of power would be reflected in differences in price, and price differences would play a critical role in ensuring economic efficiency. Resources capable of responding to variations in short-term prices, including price responsive demand, would minimize costs. ICAP approaches can preempt such responses:

- LSEs and consumers might prefer to self-insure against price risks for a portion of their load and offer demand reductions when spot prices exceed their current value for energy.

- By limiting price changes, ICAP approaches also reduce the incentives to improve generator availability and efficiently manage transmission congestion.

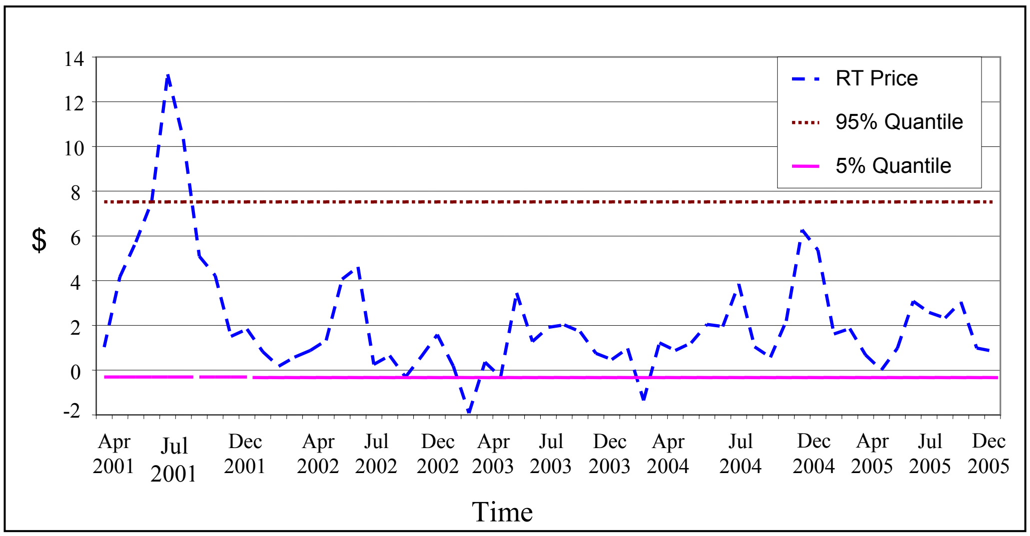
- The cost of ICAP purchases is inevitably socialized, not fully reflecting what loads would have been in a more transparent market or the cost to supply loads in different locations.

In the RTOs with separate capacity markets, expected differences in energy prices appear to be suppressed. Energy prices should be higher in transmission constrained areas where resources are in short supply than in exporting areas with ample resources upstream from transmission constraints. Indeed, one would expect to see prices that are sufficiently higher in import constrained areas with insufficient capacity to enable developers to recover their capital investment in new capacity and a return on that investment, while competitive prices in areas with surplus capacity should reflect only marginal operating costs. Given the transmission congestion into and vulnerability for reliability criteria violations on the Delmarva Peninsula, for example, one would expect average peak energy prices to be significantly higher in the Delmarva sub-region than in western PJM where there is ample capacity. Similarly, one would expect peak energy prices in the Boston-NEMA sub-region to be appreciably higher than the average prices in ISO-New England.

The Midwest ISO compared RTO reported, real-time and day-ahead market, peak period prices for areas that are known to experience tight capacity conditions and have limited import capability with those in unconstrained areas (McNamara 2006). When we examine actual energy prices, the price differentials are much smaller than would be sufficient to promote capacity investment. Figure 1 compares average monthly peak prices in PJM's real-time market (indexed to 2000 fuel prices) for the Delmarva sub-region of PJM and Western PJM. For the period April

2001 through December 2005, average peak period prices in the Delmarva sub-region were only \$2.18 / MWh higher than in Western PJM. Figure 2 provides a comparable comparison of average peak energy prices for Boston and the entire ISO-New England system. Until the spring of 2005, energy prices were actually lower in Boston than in the rest of ISO-New England. In August 2005, the average monthly price differential peaked with prices in Boston less than \$2.80 higher than those in the pool as a whole. These price differentials are far less than what an investor would require. When Delmarva and New England energy prices are compared to investor requirements, it appears that energy prices over this period were 33% too low on the Delmarva Peninsula and 53% too low in New England to permit developers to recover the cost of installing and operating a combustion turbine (McNamara 2006). To the extent that peak energy prices are lower than expected, the incentives for demand response also will be reduced.

Figure 1. Price Differential Analysis: Delmarva PJM Sub-region – Western PJM Monthly Averaged Peak Period Prices (April 2001 to December 2005)

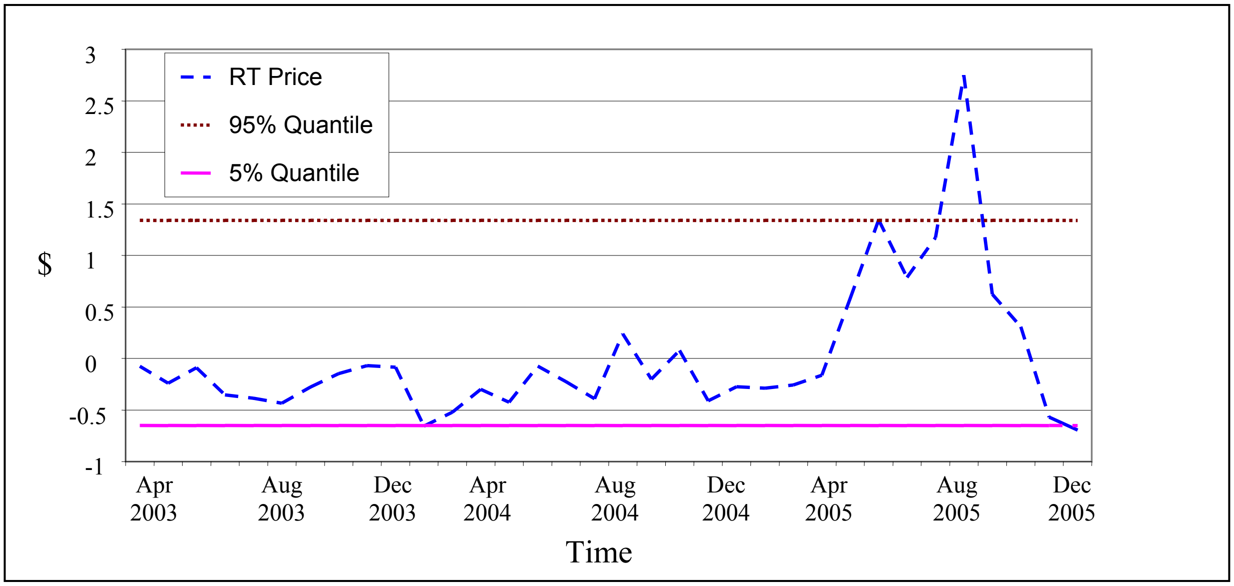


Source: http://www.pjm.com/markets/jsp/lmpmonthly.jsp (Feb. 03, 2006)

A comparable analysis compared energy prices in Western New York and Long Island. While the average peak period real-time price differential of \$9.78 per MWh between Western New York and Long Island was higher, it appears that it still would not have been profitable to install a combustion turbine on Long Island based on energy market prices alone.

To the extent energy markets are not setting prices to promote the development of new resources in areas where capacity is needed, there are five potential factors that might be suppressing such prices. First, the presence of RTO installed capacity markets and RMR contracts may keep capacity sufficiently high such that, despite reported capacity needs, these areas seldom actually reach shortage conditions. Second, the parallel revenue stream provided by these mechanisms may lead to lower offers and prices in energy markets, as suppliers cover a portion of their costs through capacity markets and RMR contracts. Third, given the lack of integration and co-optimization of energy and operating reserve markets, tight conditions that first appear in operating reserves may not be fully reflected in energy prices. Fourth, in tight

Figure 2. Price Differential Analysis: Boston – ISO New England Monthly Averaged Peak Period Prices (March 2003 to December 2005)



Source: http://www.iso-ne.com/markets/hstdata/znl_info/hourly/index.html (Feb. 06, 2005)

conditions, system operators may implement reliability measures in a manner that truncates prices. These steps might include committing additional capacity, curtailing transmission use, requesting assistance from other systems, dipping into operating reserves, or curtailing load. Finally, price caps and market power mitigation measures can limit peak prices. The Midwest ISO is evaluating how to address these considerations in its resource adequacy proposal.

Development of the Midwest ISO Resource Adequacy Plan

The Midwest ISO is developing a market based resource adequacy plan built around four objectives:

- Providing the correct and consistent market incentives: Allowing shortage costs to be reflected in energy prices will create incentives to enhance demand response, improve generator availability during peak price periods, reduce transmission congestion, and make cost-effective investments in transmission and generation.

- Improve short-term markets first: Creating a co-optimized energy and operating reserve market is cost-effective based on operating savings. Appropriate incentives in short-term markets should lead to voluntary forward contracts that can help finance investment. Experience in international markets suggests that an energy only approach can foster investment and achieve a high level of reliability (IEA 2003). While monitoring the impact of short-term market reforms on forward markets and resource development, the Midwest ISO will retain a range of fall back options in the event that an unanticipated market failure appears likely to occur.

- Creating forward looking metrics: To evaluate the extent to which energy markets are fostering resource development, the Midwest ISO intends to implement a series of resource status, forecast, and market metrics to help guide policy and market participants.

- Respecting State authority and creating an opportunity for LSEs and customers to optimize their forward market positions: As a transmission operator, the Midwest ISO's primary role is to make clear the implications of and implement the choices of consumers, LSEs, states, and balancing authorities regarding how much resource adequacy to purchase. Unlike transmission system security, resource adequacy is a largely private good. The Midwest ISO's proposal facilitates local choice by encouraging voluntary forward contracting and permitting balancing authorities, where it is technically feasible, to modify, based on LSE contracts and local regulatory decisions, the price at which load may be curtailed during shortages to protect system security.

The Midwest ISO plan evolved from what some have called an "energy-only market" approach, referring to the lack of a separate RTO requirement for LSEs to purchase capacity (Hogan 2005; Midwest ISO 2005). It has three major components.

First, the Midwest ISO will implement a co-optimized energy and operating reserve market. This co-optimized market would integrate the real-time economic dispatch of resources to minimize the combined cost of energy and operating reserves across the region. Energy and operating reserves would be priced on an integrated basis to reflect the marginal cost of providing an additional MW of energy or operating reserves respectively.

In implementing this market, the Midwest ISO will establish a demand curve for real-time operating reserves (Figure 3). In that it reflects the contingency reserve margin that is needed for secure system operations over and above the demand in the real-time market, the specification of this demand curve is comparable to specification of contingency reserve requirements today.[2]

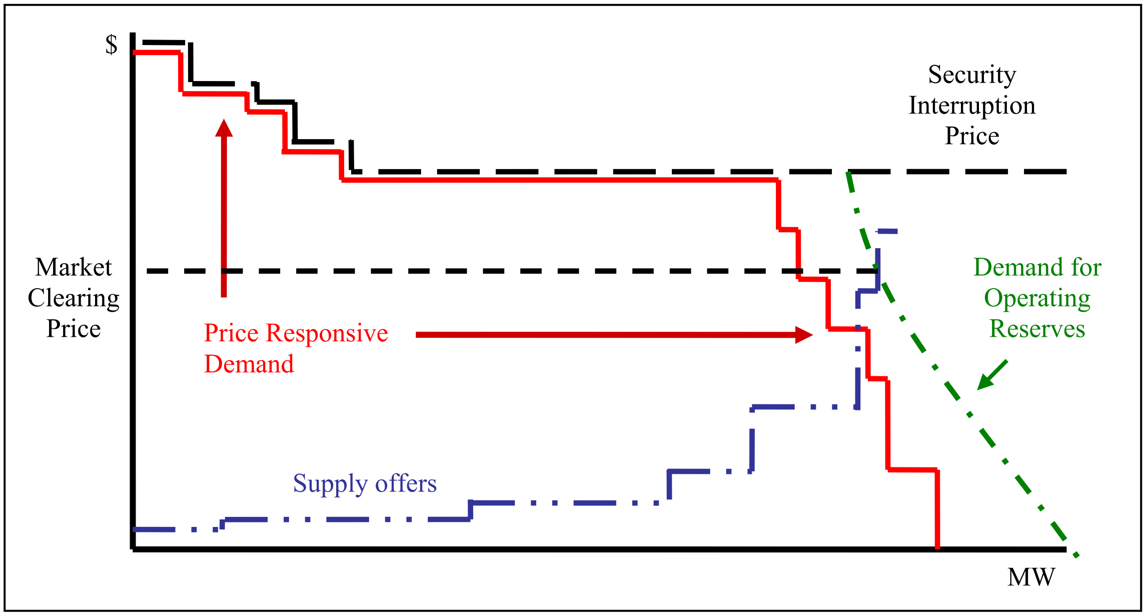
Second, the Midwest ISO will allow shortage pricing in short term markets and enhance curtailment rules for shortage conditions. To provide incentives for investment, shortage costs have to be reflected in energy prices when all available generation has been either dispatched or assigned to provide operating reserves. In shortage conditions, demand bids would set prices. Prices may exceed the caps on generator offers, which caps would remain in place to mitigate generator market power. While higher spot prices are needed to encourage investment, we expect most load to be hedged against this price risk through voluntary forward contracts.

For some consumers, purchasing very high levels of resource adequacy (e.g. 1 day of interruption in 10 years) could mean paying more for marginal resources than their willingness to pay to avoid service interruptions, i.e. their "Value of Lost Load" (VOLL). With spread of interval metering and control technology, how some consumers value electricity will be revealed through voluntary responses to energy prices. However, for loads that lack the ability to respond, there nonetheless is some high price at which consumers would prefer to be curtailed rather than have that cost rolled into their rates or contracts. In the Midwest ISO proposal, this point is called the "Security Interruption Price" (Figure 3). If prices increase to the level of this pre-determined Security Interruption Price, the Midwest ISO would instruct the local Balancing

[2] One potential difference is that as the price of operating reserves becomes transparent, a decision could be made to purchase more than the minimum required reserve when prices are low.

Authority to curtail load. The proposal contemplates, to the extent it is technically feasible, allowing States or Balancing Authorities (based on curtailment priorities, state regulation, or contracts) to modify for their loads the Midwest ISO's default "Security Interruption Price".

Figure 3. Co-optimized Energy and Operating Reserve Market



Finally, the Midwest ISO is reviewing its planning process to better anticipate resource requirements and developing metrics and continuously evaluate resource development and the performance of the forward markets used to hedge price risks and finance new investment.

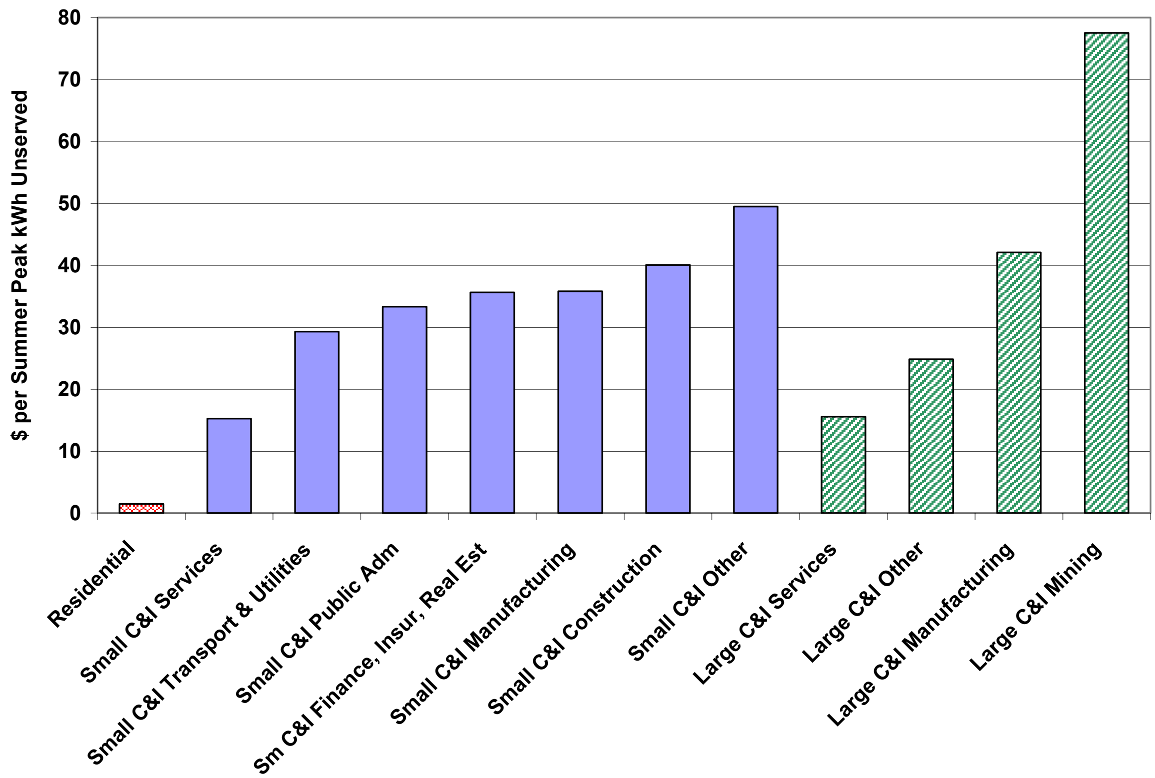
Midwest ISO Resource Adequacy Research and Analysis Program

The Midwest ISO has undertaken a multi-part research and analysis program. We have completed an analysis, using the PROMOD® production cost and power flow model, to identify the operational savings associated with regional co-optimized dispatch of energy and operating reserves. Improving the dispatch of energy and operating reserves will secure reserves at lower costs and free low cost units to generate power that would otherwise have been held back to provide reserves. This analysis evaluated the development of a co-optimized energy and operating reserve market excluding savings related to creating a Midwest ISO regional reserve sharing group with regional operating reserve requirements and consolidation of other Balancing Authority functions. The results indicate that, excluding savings related to changes in reserve requirements, development of a co-optimized energy and operating reserve market could reduce regional power production costs by $51 million to $76 million per year.

We also have evaluated the VOLL as an indicator of where the Midwest ISO should set default Security Interruption Prices. In addition to reviewing more than 100 other studies, we developed an econometric analysis of the expected outage costs for the Midwest based on models derived from a meta-data set of utility willingness to pay and damage cost surveys

(Lawton 2003). Figure 4 summarizes the median outage costs from this analysis for different customer classifications.

Figure 4. Median Estimates of Value of Lost Load for Midwest Census Regions



To provide a second indicator of where to set Security Interruption Prices a study of the expected relationship between Security Interruption Price levels and Loss of Load Probability (LOLP), given different levels of price responsive demand, also will be performed.

To better analyze longer term impacts, the Midwest ISO has initiated the development of simulation models designed to analyze the relationship between market structure, contracting preferences, and entry. And, we may undertake simulations of different market structures in an experimental economics laboratory to better evaluate how generators and LSEs may make decisions to invest in generation and demand response under different market designs.

Conclusion: The Implications for Price Responsive Demand

The Midwest ISO looks forward to working with regulators and stakeholders to facilitate a larger role for demand response in its footprint. The pace at which price responsive demand expands in the Midwest will have important implications for the volatility of energy prices, the level of Security Interruption Prices needed to achieve any given LOLP, and the frequency with which prices reach the level at which interruptions may be necessary.

The Midwest ISO's approach is intended to create two major economic incentives for the development of price responsive demand.

First, allowing demand bids to set prices and shortage costs to be reflected in higher peak and more volatile short term energy prices will increase the economic value of demand response. Demand response is by definition a short term response to changes in price. Moreover, while a new generator may take years to permit, site, and install, demand response relies on an already existing resource – load that can be more effectively managed. The incremental capital investment per kW of demand management in many cases may be smaller. The necessary control systems often can be installed in a matter of weeks or days. Unlike proposals for demand participation in capacity markets, the Midwest ISO plan would not require demand-side resources to make commitments that the underlying loads will be in operation and to reduce those load months or years in advance. Demand response could gain the full benefit of participating in the market simply by being available when needed.

Second, upon meeting applicable technical requirements, dispatchable demand reductions could provide operating reserves. Demand reductions that can be dispatched and come off line for the 30 to 45 minutes at a time – from the time a contingency occurs until reserves are replenished – are a potential low cost source of operating reserves. In a co-optimized energy and operating reserve market, operating reserves would be paid high prices during periods when meeting reserve requirements necessitates committing additional high cost generating units and when there are shortages.

The new economic incentives contemplated by the Midwest ISO's resource adequacy plan create a potentially bright future for demand response in the region.

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