

The Brattle Group

Fostering Economic Demand Response in the Midwest ISO

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I. INTRODUCTION

The demand for electric power varies over time. Demand is typically higher in the middle of the day than it is in the middle of the night. Demand also varies seasonally and ultimately, within the peak seasons, it varies with weather. Typically, the top one percent of the hours in the year account for more than ten percent of annual peak demand.

Because electricity cannot be stored economically in large quantities, it has to be consumed instantly. Thus, to meet the time-varying pattern of loads, sufficient generation capacity has to be online and available at all hours of the year to ensure that the lights stay on. In particular, to meet demand during the top one percent of the hours of the year, peaking generation capacity that runs very infrequently must be available. The cost of supplying electricity also varies by hour, depending on the operating costs of the generation units. However, few end use customers see this time variation in their electric rates. Most of them see flat rates, which provide them no incentive to use less energy during peak times when power is very expensive and to use more during off-peak times when power is comparatively inexpensive.

This leads to economic inefficiency in the consumption and production of electricity and may lead to excessive investment in the amount of capacity that is needed to achieve resource adequacy. The best way to solve the problem would be send price signals to end-use customers that vary with the cost of power. Examples include time-of-use (TOU) rates, which don't vary dynamically, and rates such as critical peak pricing (CPP) and real time pricing (RTP) which vary dynamically. Both would be an improvement over flat rates, although dynamic pricing rates would raise economic efficiency more than static TOU rates.¹

The pricing of electricity to end users falls within the purview of state regulation. State commissions throughout the country are giving serious consideration to dynamic pricing rates. However, this matter will not be resolved any time soon, in part because a transition from flat rates to dynamic pricing rates may create winners and losers and in part because the institution of such rates has to be accompanied by the installation of advanced metering infrastructure.

¹ See Ahmad Faruqui and Stephen S. George, "The Value of Dynamic Pricing in Mass Markets," *The Electricity Journal*, 15:6, 45-55, 2002.

In the absence of retail dynamic pricing rates, a second best solution is for the Regional Transmission Organization (RTO, or ISO) to enable demand response (DR) at the wholesale level. DR comprises measures that can reduce consumption during certain hours from normal consumption patterns.² DR resources can be classified into three categories, although some resources can be more than one type: *emergency* DR, *economic* DR, and *ancillary services* DR. Emergency DR resources are callable by the RTO during system emergencies and thus can play an important role in supporting system reliability while reducing the need for generation capacity. Economic DR participates in (or responds to) energy markets not only during emergencies but any time spot energy prices become high. This can make electricity markets more competitive and efficient by increasing the elasticity of demand and/or competing against generating capacity and limiting supplier market power. It can have the effect of mitigating peak prices and reducing price volatility. Economic DR can be implemented entirely through retail rates or it can be enabled by RTOs in various ways, as discussed in the rest of this whitepaper. Ancillary services DR resources provide contingency reserves or regulation to help balance the system in real-time and thus must be controlled directly or monitored closely by the RTO. This whitepaper primarily addresses economic DR.

Load-serving entities (LSEs) in the Midwest ISO have a large amount of emergency DR, much of which derives from legacy utility programs. However, in comparison with some of the other RTOs, the Midwest ISO has substantially less economic DR participating in its energy markets. This difference seems to be driven largely by disparities in rules, rate structures, and enabling technology, as well as the fact that PJM, NYISO, and ISO-NE provide payments for demand response.³ As a result of the limited amount of economic demand response, the Midwest ISO is seeking ways to enhance the participation of economic demand response in its markets where it would be cost effective. This goal is motivated by the potential for DR to make electricity

² Demand response differs from energy efficiency in that while energy efficiency measures seek to decrease overall energy consumption, demand response decreases consumption only in target hours such as on-peak consumption. Some DR measures may result in no overall decrease in energy consumption, but are nonetheless useful because they shift consumption from high demand periods to low demand periods.

³ The Midwest ISO provides payments to DR based on its participation as a demand side resource with some limited payments to DR as supply, whereas the other mentioned ISOs and RTOs primarily provide payments to DR as supply. This issue is discussed in detail in the body of this paper.

markets more efficient and competitive, while supporting reliability, and to reduce capacity costs.

This whitepaper by *The Brattle Group* describes measures that the Midwest ISO can take to foster the development of economic DR to its cost-effective potential and to efficiently integrate such resources into its day-ahead and real-time energy markets. The objectives of this report are to:

- Identify approaches to integrating the various types of DR into energy markets. (This whitepaper does not address emergency DR or ancillary services DR or their participation in RTO markets.)
- Evaluate the efficiency and feasibility of the various approaches
- Identify and evaluate RTO and state-level enabling factors for the various approaches
- Assess current DR and DR potential in the Midwest ISO
- Based on the above, develop a vision for the future of economic DR in the Midwest ISO
- Recommend changes to Midwest ISO business rules to enable this vision and provide input to states that have jurisdiction over Midwest ISO participants

In brief, we recommend that the Midwest ISO enable the participation of curtailment service providers (CSPs) in its energy markets as at least a bridge to a future in which the states enable the first-best approach to economic DR by implementing widely retail rates with dynamic pricing. We provide a two-year roadmap focused on: (1) establishing a customer baseline load (CBL) methodology, measurement and verification (M&V) protocols, and settlement changes to enable CSPs; and (2) engaging state commissions and utilities in discussions about the benefits of demand response and the steps toward their implementation of dynamic retail rates.

II. OVERVIEW OF DR AT THE END-USER LEVEL

DR ultimately happens at the end-user, or consumer, level. As such, the integration of DR into RTO market operations should, if possible, take into account the characteristics of end-user programs. Therefore, we begin with some brief descriptions of the various types of DR at the end-user level grouped into load control programs and pricing programs.

One key characteristic of each type of program that will be important for identifying the RTO's role in promoting and integrating economic DR is whether the end-use application is "LSE-callable" or not.⁴ LSE-callability is clearly important for emergency DR. It is also important for economic DR to the extent that it allows active integration into energy markets. Non-LSE-callable DR can *respond* to observed or anticipated prices (thus helping to reduce demand when market conditions appear to be tightest), but its dispatch can not be actively coordinated with system conditions, as LSE-callable DR can be. Active coordination is desirable for more effective RTO dispatch.

A DR program is LSE-callable if the LSE must make a choice as to trigger load reductions either day-ahead or in real-time. An example of LSE-callable DR is direct load control (DLC) of air conditioners, where an LSE "flips a switch" to turn down an air conditioner. Pricing programs in which rates are elevated under certain market or system conditions can also be considered "callable" if the LSE must make a decision as to when the rates are elevated.⁵ Some believe that pricing programs are callable only in a statistical sense, even though the response from DLC is also subject to uncertainties. The difference is that pricing programs depend on end-user behavior, whereas DLC depends on a physical mechanism. An example of a DR program that is not LSE-callable is time-of-use rates, where the prices for peak hours are set ahead of time. Once the tariff is in place, the LSE has no decision to make as to the prices to charge. The

⁴ It might be argued that RTOs should push for exposure to real-time prices rather than consider LSE-callability. However, many think that real-time prices might not include all the components of generation costs such as capacity costs. Moreover, as a practical matter, the movement in price responsive demand seems to be towards rates that are LSE-callable not RTP.

⁵ For instance, real-time pricing (RTP) programs that simply pass on market prices are typically not LSE-callable, but critical peak pricing programs (CPP) where prices are high only around 10 to 20 times per year are LSE-callable.

following sections describe these programs and others in more detail, with particular emphasis on LSE-callability and implications for RTO market integration.⁶

II.A LOAD CONTROL PROGRAMS

Load control programs reduce load through pre-arranged protocols. Typically, the LSE pays end-users for agreeing to reduce their usage of a particular type of equipment (air conditioning, for instance) a certain maximum number of times per year. Load control programs come in three types: (1) direct load control; (2) indirect load control; and (3) interruptible programs.

II.A.1 Direct Load Control (DLC) Programs

One of the major classes of DR is direct load control. In DLC programs, the LSE has the ability through a communications system to curtail some major end-use of a customer. Examples of this are controls over air conditioning, water heaters, space heaters, and pool pumps. Notification requirements vary and range from day-ahead to none at all. Clearly, the notification requirements will affect which RTO markets (Day-Ahead or Real-Time) a DLC program can participate in. For example, if day-ahead notification is required, then participation in a real-time market could be impacted.

II.A.2 Indirect Load Control (ILC) Programs

Under indirect load control (ILC) programs, customers respond to a signal from either a load serving entity (LSE) or curtailment service provider (CSP) to reduce load. The difference from DLC is that ILC program participants retain control of their equipment so that response to the signal is voluntary. ILC is often used by CSPs according to our interviews with them.

⁶ There are other types of DR that are contemplated as playing a large role in the grid in the future. Such applications as Plug-in Hybrid Electric Vehicles (PHEVs) and smart appliances may well change the landscape for DR over the long term. Smart Grid resources are likely much more flexible than the short-term and medium-term resources outlined in this Section. Balancing with intermittent resources then is not a likely application for the energy market resources discussed here as that requires the sort of flexibility required by resources participating in Ancillary Services markets.

II.A.3 Interruptible Rates

Interruptible rates are used to induce demand response under emergency conditions but are generally not considered to be a form of dynamic pricing since they are not typically dispatched for economic reasons. Customers sign up for the rate and agree to curtail a prearranged amount of load in return for a rebate or discounted electricity price. In some cases, the curtailment is mandatory and the customers face a substantial penalty if they do not curtail. Other programs are voluntary and only provide an incentive for curtailment without the penalty. Interruptible rates typically have a minimum size requirement for eligibility and only apply to C&I customers. However, the concept is general and can be applied to residential customers, as was demonstrated by Southern California Edison in the early 1980s through its Demand Subscription Service program.⁷ As will be discussed in Section VI, interruptible rates are widespread in the Midwest ISO.

A characteristic of interruptible rates that distinguishes them from other forms of dynamic pricing is that they are typically “triggered” by system-reliability conditions rather than being dispatched economically. For this reason, interruptible rates have been successful in inducing demand response and peak reductions to support system reliability, but they are typically not considered to portray accurate price signals. That said, interruptible rates are a form of LSE-callable DR programs that could be used as economic DR, if interruptions were triggered based on prices.

For example, Wisconsin Public Service (WPS) modified its legacy interruptible program to allow bidding in price responsive demand in the Midwest ISO day-ahead market.⁸ WPS’s CP-I2 rate is targeted at commercial and industrial customers with interruptible demand of 200 kW or more. Program participants are subject to emergency and economic interruptions for a maximum of 300 hours per year for legacy DR, and 600 hours per year for interruptible DR enrolled more recently. Emergency interruptions are declared during system reliability events, while economic interruptions are declared when the wholesale market prices significantly exceed WPS’s

⁷ Southern California Edison Company, “Demand Subscription Service Test,” Rosemead, California, 1982.

⁸ Dennis Derricks (Wisconsin Public Service Corporation), FERC Wholesale Demand Response Technical Conference, transcript, 186.

Economic Interruption Trigger Price (EITP). Economic interruptions may occur if the Midwest ISO's day-ahead LMP exceeds the EITP, or if the real-time LMP is expected to exceed the EITP. Customers have a "buy-through" option to specify a quantity and price at which they are willing to buy energy day-ahead instead of paying the real-time prices.

II.B PRICING PROGRAMS

The second major type of end-user DR program is pricing programs. Price-based DR typically refers to the family of time-varying retail rates, also known as dynamic pricing. These rates provide customers with a price signal that varies over the course of the day to reflect the higher cost of providing electricity during peak times (when demand is high) than off-peak times (when demand is lower). In addition, these rates have a feature that allows the price signal to be sent to customers on a day-ahead, or even, day-of, basis. This flexibility allows for a rate that more accurately reflects market prices, providing a higher retail rate on days when wholesale market prices are at their highest and a lower retail rate on days when wholesale market prices are lower. While there are many variants of pricing programs – and the same end-user could participate in both a load control program and a pricing program – this paper concentrates on the major types.

II.B.1 Time-of-Use Rates

A very simple type of rate-based DR program is a time-of-use rate (TOU).⁹ TOU rates divide the day into fixed time periods and provide a schedule of rates for each period. For example, a peak period might be defined as the hours from 12 pm to 6 pm on weekdays, with the remaining hours being off-peak. The rate is higher during the peak period and lower during the off-peak, mirroring the typical variation in the cost of supply that is needed to serve load. The different rates or their timing are not dynamically determined, and hence the end-user's "response" is neither dynamic nor callable. The implications for TOU rates at the RTO level are minimal except for their effects on demand forecasts. This, of course, could have an effect on capacity requirements for an LSE.

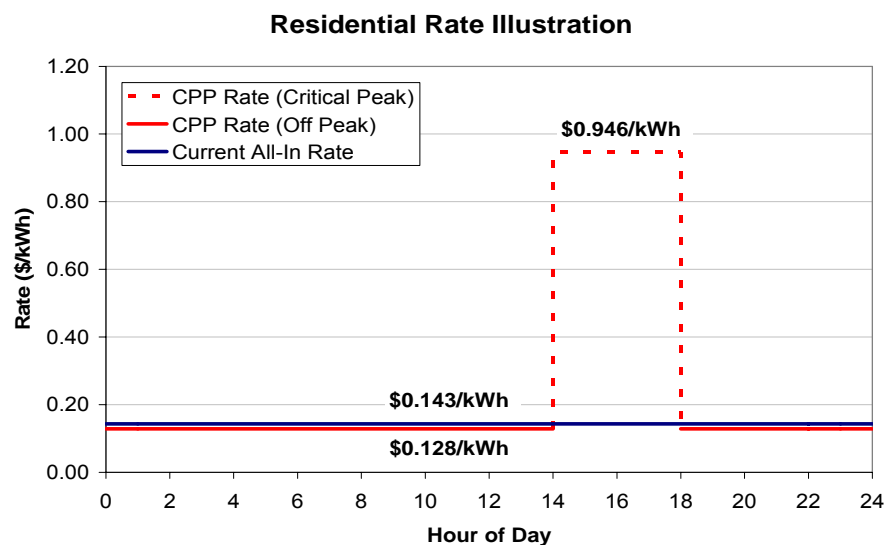
⁹ Some discussions exclude TOU rates from the category of dynamic pricing because the days, times, and levels of prices are fixed. While we generally agree with that taxonomy, we include TOU here for completeness of discussion.

II.B.2 Critical Peak Pricing (CPP)

Under a CPP rate, participating customers pay higher prices than they would pay on their otherwise applicable tariff during peak hours on the few days when wholesale prices are the highest. In return, the customers pay a lower non-critical peak price that more accurately reflects lower, non-critical peak energy supply costs for the remainder of the season (or year). Thus, the CPP rate serves to convey the cost of power generation to electricity customers and provides them with a price signal that more accurately reflects energy costs, as well as the opportunity to minimize their electricity bills. This rate form is particularly effective when elevated supply costs are limited to only a relatively few (under 100) hours of the year, and their onset is predictable. Figure 1 below illustrates the concept.

FIGURE 1: CRITICAL PEAK PRICING

- Critical peak and off peak prices should reflect system costs
- Revenue neutral
- 10 to 20 critical days during summer, 4 to 6 hours per critical event (60-120 hours per summer)
- Can also be layered on a TOU rate or an inverted tier rate



CPP is not currently available in most parts of the U.S. It has, however, been offered to small customers by Gulf Power in Florida. In Gulf Power’s “GoodCents Select” program, the CPP rate is offered as a rider on top of a TOU rate. Gulf Power estimates that it had roughly 6,000 participants enrolled by 2003, accounting for roughly one MW of demand reduction.¹⁰ While

¹⁰ FERC Staff. “Assessment of Demand Response and Advanced Metering.” August 2006. Page 58.

this amount of coverage is low, with the installation of AMI CPP may become a major vehicle for providing DR in the future.

Outside of the United States, a form of CPP is being offered by Électricité de France (EDF), through their *tempo* rate program. This program features two daily pricing periods and three types of days, which are named after the colors of the French flag. The blue days are the most numerous (300) and least expensive; the white days are the next most numerous (43) and mid-range in price; and the red days are the least numerous (22) and the most expensive. The ratio of prices between the most expensive time period (red peak hours) and the least expensive time period (blue off-peak hours) is about ten, reflecting the corresponding ratio in marginal costs. CPP was originally offered in France in 1993 as a voluntary program and currently has over 120,000 enrolled participants.¹¹

The designation of a day as a critical peak day is “callable” by the LSE, and such designation triggers a reduction in load. However, there are key questions as to whether it can be integrated into RTO energy markets. These include issues of:

- When the critical peak day is called (day-ahead or day-of);
- Enabling technology for the end-user which would allow for automated response by the customer; and
- Variability and unpredictability of the response.

II.B.3 CPP-Variable Pricing (CPP-V) and Variable Peak Pricing (VPP)

Two variations on the CPP rate are CPP-V and VPP. CPP-V is similar to the CPP rate, with the exception that the duration of the peak period is not fixed. The event duration notification is generally provided to participants on a day-ahead basis at the same time that they are notified of the upcoming critical event. This provides utilities and RTOs with the flexibility to respond to emergencies and high-priced periods of varying lengths occurring at different times of the day.

¹¹ Denise Giraud, “The Tempo Tariff,” Efflocom Workshop, June 10, 2004. <http://www.efflocom.com/pdf/EDF.pdf>. For the current tariff, consult <http://www.edf-bleuciel.fr/accueil/mon-quotidien-avec-bleu-ciel-d-edf/option-tempo-41090.html&onglet=5>.

It is also possible to vary the critical peak price, rather than locking it in at a pre-specified level. CPP rates with this characteristic are called VPP rates. They provide a price signal to customers that more accurately reflects contemporaneous system conditions and marginal costs. VPP rates can also introduce uncertainty in the timing and duration of the peak period, similar to CPP-V rates.

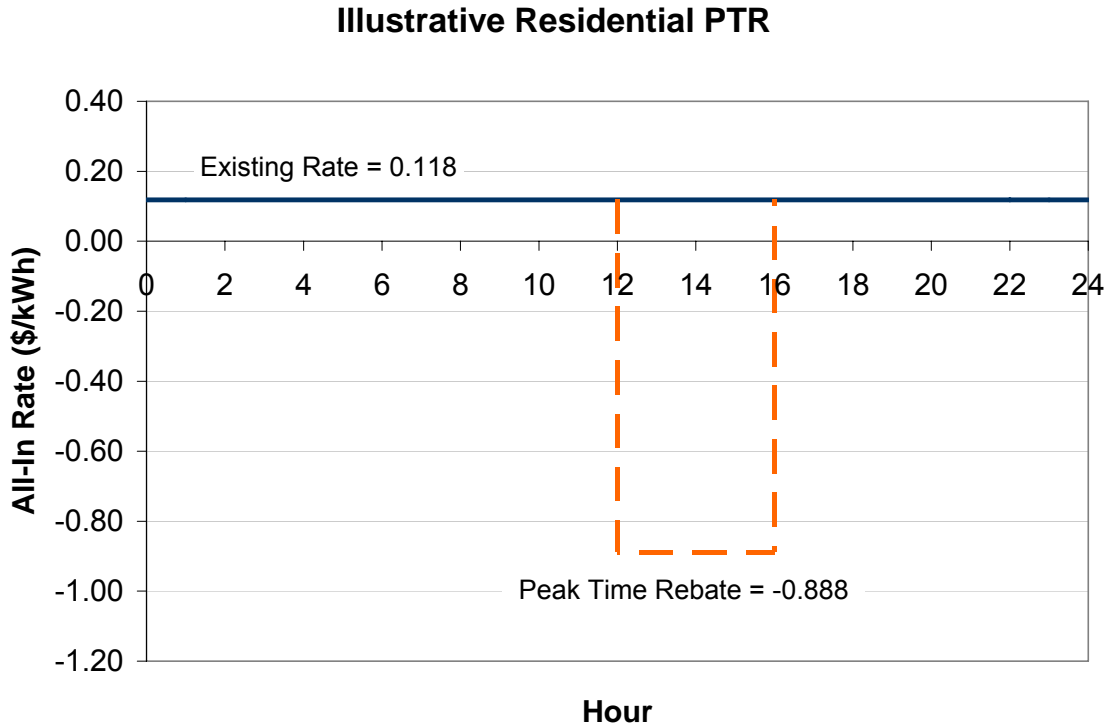
VPP and CPP-V are not currently being offered anywhere, although a VPP rate has been approved for implementation in Connecticut as the default service rate for customers over 300 kW. Also, CPP-V was tested in the California Statewide Pricing Pilot (SPP). The results showed that customers on a CPP-V rate produced peak reductions that were 25 percent larger than those of customers on a standard CPP rate.¹²

II.B.4 Peak Time Rebate (PTR)

If a CPP tariff cannot be rolled out because of political or regulatory constraints, some parties have suggested the deployment of a peak-time rebate (PTR, which is also known as critical peak rebate, or CPR). Instead of charging a higher rate during critical events, participants have the opportunity to buy through at the existing rate; however, they can earn a significant cash rebate (¢/kWh) for reducing load during the critical period. This, of course, requires the establishment of a baseline load from which the reductions can be computed. Figure 2 below illustrates the concept.

¹² CRA International, "Impact Evaluation of the California Statewide Pricing Pilot," March 16, 2005.

FIGURE 2: PTR IS AN INVERSE CPP RATE



PTR rates are also LSE-callable and face similar issues as does CPP regarding integration at the RTO-level:

- When the critical peak day is called (day-ahead or day-of);
- Enabling technology for the end-user; and
- Variability of the response.

As mentioned above, PTR rates require the establishment of a customer baseline load (CBL).

However, depending on the method of integration into an RTO, this may or may not have implications for requiring measurement and verification (M&V) processes at the wholesale level

II.B.5 Real Time Pricing (RTP)

Participants in RTP programs pay for energy at a rate that is linked to the hourly (day-ahead or real-time) market price for electricity. Depending on their size, participants are typically made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers — usually above one MW of load — face hour-ahead prices. These programs post

prices that most accurately reflect the cost of producing electricity during each hour of the day, and thus provide the best price signals to customers, giving them the incentive to reduce consumption during the most expensive periods.

Over 70 utilities have offered RTP either as a pilot or a permanent program.¹³ RTP programs are typically offered only to large C&I customers on an opt-in basis, although customers in several states with retail choice have RTP as a default rate for large customers that remain with their incumbent utility. Georgia Power has one of the most successful RTP programs for C&I customers. With over 1,600 enrolled customers, the utility reports having achieved a 750 MW reduction during high-priced hours.¹⁴ This represents seventeen percent of all participants' coincident peak demand during those hours.¹⁵ Depending on the price level, the fraction of participants responding to RTP ranged from forty percent to eighty percent.

However, in a recent survey of 65 utilities (both domestic and international), only one (Commonwealth Edison) currently offers residential RTP.¹⁶ Through this program, participants are notified of hourly prices on a day-ahead basis and receive a participation credit in addition to any bill savings that they could realize by participating in the program. The program was expanded to all residential customers in January 2007 after approximately 1,100 customers, representing roughly 330 MW of demand, participated in the RTP pilot. The Illinois commission recently decreed that RTP is to be made available to all residential customers.

II.B.6 An Alternative Approach to RTP Rate Design

The RTP rate that was described previously allocates all components of the retail rate, including capacity costs, across all hours. An alternative approach could be to allocate the cost of capacity

¹³ Galen Barbose, Charles Goldman, & Bernie Neenan, "A Survey of Utility Experience with Real Time Pricing," *Lawrence Berkeley National Laboratory: LBNL-54238*, 2004.

¹⁴ Braithwait, Steven and O'Sheasy, Michael. "RTP Customer Demand Response," In Ahmad Faruqui and B. Kelly Eakin (editors) *Electricity Pricing in Transition*, pages 181-190, 2002, Kluwer Academic Publishers.

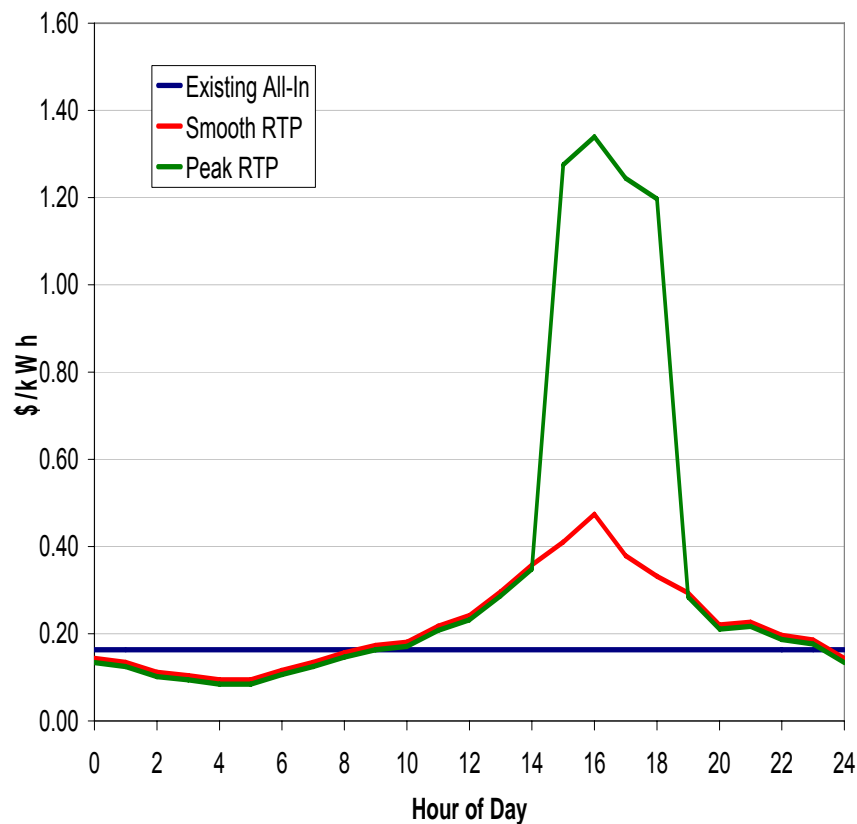
¹⁵ GAO, "Electricity Markets: Consumers Could Benefit from Demand Programs, But Challenges Remain" (GAO-04-844, August 2004), 22-23.

¹⁶ Energy & Environmental Economics, "A Survey of Time-of-Use Pricing and Demand Response Programs," July 2006, Page 6.

needed during peak only to the critical peak hours, using a methodology similar to that used to develop a CPP rate. This would send a stronger price signal to customers and, as a result, encourage greater demand response at times when it is needed most.¹⁷ To the extent that hourly electricity prices do not reflect this capacity cost, this may also be a more equitable means of allocating the costs.

This alternative RTP design is referred to in this study as the Peak RTP. An illustration of how this rate would differ from the standard RTP rate design (referred to hereafter as the “Smooth RTP”) is shown in Figure 3.

FIGURE 3: COMPARISON OF PEAK RTP TO SMOOTH RTP ON CRITICAL DAY



The Peak RTP rate is significantly higher than the Smooth RTP during critical hours, but presents an off-peak discount during all other hours of the year. This would provide customers

¹⁷ This alternative approach enables customers to create and capture capacity value as well as energy value. This approach could be efficient even in the Midwest ISO, where resource adequacy requirements apply to all hours, but the need for marginal capacity is still driven by the summer peak.

with opportunities for larger bill savings and, thus, a greater incentive to shift load away from the critical peak periods.

Depending on the particular implementation of RTP it could be either LSE-callable or not. Some forms of Peak RTP that have been posited are not based on a prior notification of end-users, although in theory Peak RTP could include day-ahead notification that the capacity price adder will be imposed the next day.

II.C CONCLUSIONS

As discussed above, the important types of end-use DR programs that may require careful integration into RTO markets are those that are LSE-callable. Programs that are not LSE-callable, such as TOU or Smooth RTP, will have an impact on the load forecast but may not require substantial wholesale market redesign to accommodate them. By contrast, DLC, interruptible rates, and dynamic rates, such as CPP, may require careful consideration in order to integrate them into RTO energy markets.

III. MODELS FOR INTEGRATING DR INTO ENERGY MARKETS

In most commodities markets, demand-side bidding takes place as a matter of course. Most commodities are storable and purchasers will buy and store the commodity when prices are low to soften the effects of price spikes.¹⁸ Apparent demand elasticity at any given time in a commodity market can occur, then, in two ways. First, it can be reflected in the underlying demand elasticity of the commodity. As the price of a commodity rises, buyers purchase less because, for instance, they can do without it, or substitute another good for the commodity. Second, purchasers can spread out their purchases through time and thus avoiding purchases when the price seems too high.¹⁹ In electricity there is little storage, but the spreading phenomenon can be seen in two-settlement markets, *i.e.* between the day-ahead and real-time markets. Buyers can choose from which market to purchase. When there is an ability to submit demand-side bids, buyers can shape their bid in the day-ahead market based on their expectations of what the real-time price will be. For example, a buyer with 1000 MW of load might buy 900 MW in a day-ahead market hoping that 100 MW might be bought more cheaply in real-time. This sort of “structurally induced” demand elasticity is a feature of two-settlement markets that is now often actively encouraged in order to provide greater liquidity to the markets.²⁰ Traders often engage in buying in a day-ahead market and selling in a real-time market (or vice versa) using so-called virtual bids, in order to try to profit from the difference in prices. This practice is sometimes called intertemporal arbitrage.

In theory, an LSE has an incentive to use DR in order to earn greater profits (or savings for its customers). The way it would do this is similar to the way that trading firms profit in other commodity markets. When the price is high in the wholesale market, the LSE would use demand response to reduce the load that it has to serve and thereby either avoid having to purchase power at a high price in the wholesale market (or, perhaps be able to sell power it

¹⁸ Alternatively, buyers can take advantage of the many financial tools that exist in order to hedge risk: forwards, options, *etc.*

¹⁹ This is similar to stock traders who “dollar cost average” their position in a stock, by spreading their purchases over time to avoid buying at peak prices.

²⁰ For a study of structurally-induced demand elasticity in the California market prior to the crisis, see Robert Earle, “Demand Elasticity in the California Day-Ahead Market”, *The Electricity Journal*, October 2000.

would otherwise use to supply its end-use customers). Some analysts of DR claim that this is the only appropriate use of DR and demand-side bidding in wholesale markets (as opposed to intertemporal arbitrage). In what follows, we describe the various approaches to enable DR participation in wholesale energy markets.

III.A MECHANISMS FOR PARTICIPATION OF DR IN RTO ENERGY MARKETS

RTO markets can incorporate DR into energy markets in three basic ways:

- The “no curves” approach
- The “demand curves” approach
- The “supply curves” approach

III.A.1 “No Curves”

Under the “no curves” approach, demand is taken as a given by the RTO, and generator schedules and dispatch are established against a fixed level of demand. This does not mean that demand is completely inelastic, but merely reflects the fact that such price response is not fully integrated into the wholesale market process (*i.e.*, dispatch and market clearing). In general, demand reacts to both the expected price for the period scheduled or dispatched, as well as it reacts to the prices established in previous periods as part of the process of establishing expectations for what the price will be. If prices are expected to be high, then consumption is reduced in response. Australia is an example of this where demand-side bidding is limited and demand is essentially a vertical curve in the market clearing mechanisms of the market operator.²¹ While there is reaction on the demand side, the “no curves” has less benefit than full integration into the wholesale market because the triggering of load reductions is not coordinated ahead of time with market clearing. For example, a load reduction or CPP price increase might be called when prices are expected to be very high, but actual prices are not as high as expected. Such curtailments are inefficient, because the LSE would not have curtailed had it foreseen the actual real-time price. The inefficiency is smaller when the load reduction is called in real time instead of day ahead, because the discrepancy between actual and expected prices tends to be

²¹ Robert Earle and Ahmad Faruqui, *Demand-Side Bidding in Wholesale Electricity Markets*, Australian Energy Markets Commission, June 2008.

smaller. In addition to uncertainty regarding price forecasts, unintegrated DR can influence the price, but it can never set the price. Enabling price setting by demand curve bids incorporates price response into the wholesale market, and is the essence of the “demand curves” approach explained below.

III.A.2 “Demand Curves”

The “demand curves” approach allows for the submission of sloped demand curve bids in the energy markets. Under this model, the benefit from DR would accrue to buyers and sellers of power in the same way it does in most commodity markets. Holders of a short position (those who need to buy) could reduce their short position and buy less during times of high prices, while holders of long positions (those who have product to sell) could increase their long position and sell more during times of high prices.

Most RTOs in the United States have mechanisms for sloped demand curve bids in day-ahead markets, where they exist. The challenge for integrating DR into energy markets has to do with matching end-use DR programs with the characteristics of the scheduling, bidding, and market clearing processes at the RTO. For example, if the notification time for a retail day-ahead dynamic price program occurs before market close, then integration of that retail program into a day-ahead demand bid is not possible. Submission of sloped demand curves in real-time holds fascinating possibilities, but there are technical and program design challenges such as communications and rate design. Direct and indirect load control programs provide possible avenues to obtain sloped demand curves in real-time markets.

III.A.3 “Supply Curves”

Under the “supply curves” approach,²² the RTO pays DR for reducing load as if it were supply. This approach would appear to be justified when the normal mechanisms of a market in the “no

²² One disadvantage to the “supply curves” approach, as compared to subjecting retail customers to real-time pricing, is that it only discourages consumption when prices are high; it doesn’t encourage consumption when prices are low (e.g. at night). Both of these effects increase economic efficiency but ISO programs can only facilitate one of them. Utilities are beginning to recognize that the plug-in hybrid car will be a key element of future energy policy and will require customers to be able to access cheap electric rates at night.

curves” or “demand curves” approaches are not working, or there is some larger benefit that accrues to society and, on that basis, payments to demand for reductions might be justified. A discussion of the levels of payments can be found in Section V of this paper.

Along with the question of what the level of payment for DR should be under the “supply curves” approach is that a customer baseline load (CBL) must be established along with measurement and verification (M&V) procedures in order to make the “supply curves” approach work. The RTO must know that the consumption has been reduced in comparison to what would have otherwise occurred. This is further addressed in Section V of this paper.

The “supply curves” approach, of course, faces some of the same integration issues with RTO operations as does the “demand curves” approach including timing, issues regarding price setting, variability of response, and general compatibility between end-user DR programs and RTO business rules.

III.B INTERSECTION OF DR ENERGY MARKET PARTICIPANTS WITH RTO MECHANISMS

For each of the three mechanisms outlined above, there are three groups of potential participants or agents in making DR happen in RTO energy markets:

- Wholesale end-users;
- Load Serving Entities (LSEs); and
- Curtailment Service Providers (CSPs).

Depending on the type of participation that is allowed through RTO rules, each of these interacts with the RTO in different ways. Table 1 below gives a high level summary of the interactions. Each cell in the matrix describes a basic business model for economic DR.

TABLE 1: INTERACTION OF DR PARTICIPANTS WITH RTO DR MECHANISM TYPES

Market Participant	RTO Mechanism	“No Curves”	“Demand Curves”	“Supply Curves”
End-User		LSEs/wholesale consumers adjust consumption in response to price signals	Wholesale end-users submit demand curves to reflect their ability to decrease consumption	Wholesale end-users submit DR supply curves to reflect their ability to decrease consumption
LSE		LSE deploys DR in response to market prices	LSE integrates DR end-use programs with demand curves reflecting the marginal value of power	LSE offers DR as supply. May prefer to “demand curves” because of bidding and settlement provisions
CSP		No role for CSP except as contractor for LSE or wholesale customers	No role for CSP except as contractor for LSE or wholesale customers	CSPs enrolled end-use customers in DLC or ILC programs and aggregate DR assets as supply resources

IV. IMPLEMENTATION OF THE MODELS: EXAMPLES, ENABLING ELEMENTS, AND BARRIERS

As discussed above, there are several models for integrating price-responsive demand into energy markets. The variation exists to suit differences in customer characteristics (size, metering and communications infrastructure, price risk aversion), differences in state regulatory structures, and largely just different degrees of innovation in promoting DR. A close examination of the various approaches reveals differences in implementation barriers, economic efficiency, and long-term potential. There are also differences in implementation requirements for the RTO, and differences in the amount of impact on RTO energy markets. Some programs are clearly working very well and could form a large part of Midwest ISO's long-term vision.

Along with a review of the literature, we examined the various approaches to DR by interviewing staff at the following DR providers and enablers:

- LSEs: Wisconsin Public Service Corporation (WPS), Detroit Edison (DTE), Potomac Electric Company (Pepco), Baltimore Gas & Electric (BG&E), Commonwealth Edison (ComEd), Public Service Enterprise Group (PSE&G)
- CSPs: EnerNOC, Comverge/Enerwise, Energy Curtailment Specialists, Viridity
- RTOs: PJM, ISO New England

We present our findings in the following categories shown in Table 2:

TABLE 2: INTERVIEWS OF MARKET STAKEHOLDERS ON DR PARTICIPATION AT RTOs

RTO Mechanism		“No Curves”	“Demand Curves”	“Supply Curves”
Market Participant	End-User	Wholesale end-users adjust consumption in response to price signals No interviews conducted	Wholesale end-users submit demand curves to reflect their ability to decrease consumption No interviews conducted	Wholesale end-users submit DR supply curves to reflect their ability to decrease consumption Section IV.F
	LSE	LSE deploys DR in response to market prices Sections IV.A, IV.B	LSE integrates DR end-use programs with demand curves reflecting the marginal value of power Section IV.C	LSE offers DR as supply. May prefer to “demand curves” because of bidding and settlement provisions Section IV.D
	CSP	No role for CSP except as contractor for LSE or wholesale customers N/A	No role for CSP except as contractor for LSE or wholesale customers N/A	CSPs enrolled end-use customers in DLC or ILC programs and aggregate DR assets as supply resources Section IV.E

IV.A DYNAMIC PRICING BY LSEs NOT ACTIVELY INTEGRATED INTO RTO ENERGY MARKETS (A “NO CURVES” APPROACH)

IV.A.1 Basic Description

As discussed in Section II, the general concept of end-user dynamic pricing is to expose customers to spot prices so that they can make efficient consumption decisions and reduce demand when supply becomes scarce. There are many variants of dynamic pricing including CPP, PTR, and pure real-time pricing. In general, most load is not on dynamic pricing because of a reluctance to expose customers to volatile prices as well as a lack of enabling infrastructure among small customers. However, some larger customers have dynamic retail rates, and many states are beginning to experiment with pilot programs for introducing dynamic pricing into the

residential sector.²³ In the absence of an ability to bid through “demand curves” or “supply curves,” LSEs must form an estimate of market prices in order to know when to use their LSE-callable DR. This estimate could be based on the recent history of LMP prices, which RTOs including Midwest ISO display on their website for each dispatch interval.

IV.A.2 Enabling Elements at the RTO Level

The RTO does not have to do anything other than provide price transparency to enable dynamic pricing to respond to wholesale market conditions (unlike dynamic pricing with active participation in the wholesale market, as described in Sections IV.B and IV.C).

IV.A.3 Enabling Elements at the State/Utility Level

Dynamic pricing is possible only if state regulators allow it (or if they allow retail access and competitive retail providers offer it). This requires a departure from the old construct where customers could have as much power as they wanted any time at fixed retail rates. It sounds undesirable until regulators realize that fixed rates must contain a significant premium to cover the cost of serving load that lacks incentive to reduce during the highest-priced periods (while the LSE takes all the price and volume risk). There has been some willingness to implement dynamic rates among large customers, but only nascent interest in offering dynamic pricing (and charging a premium for fixed rates) for smaller customers. There is a very substantial educational challenge to demonstrate to states the potential customer savings from dynamic pricing.²⁴

The second major necessary enabling element for dynamic pricing is interval metering and communications equipment. The largest customers typically have this equipment. Equipping smaller customers would require major investment in new meters, which several states are planning and many others are considering. At a basic level, the equipment that is minimally needed to enable dynamic pricing is an interval meter that records consumption by time period

²³ For a survey of recent pilot activity, consult Ahmad Faruqui and Sanem Sergici, “Household response to dynamic pricing: a survey of seventeen pricing experiments,” November 13, 2008. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1134132

²⁴ There is some evidence that state regulators are beginning to consider dynamic pricing, through activities conducted at MADRI and MWDRI.

and a means of communicating what the prices are (RTP, for example) and when a critical event is occurring (CPP, for example). This minimum, of course, can be enhanced by higher levels of technology such as in-home displays, thermostats that can receive a signal from the LSE, and other enabling technologies.

There are additional state and LSE-level challenges in restructured states where the utilities outsource the responsibility for supplying generation to standard offer service (SOS) customers. In such cases, either the dynamic pricing structure needs to be incorporated into the SOS auctions, or LSEs must define a baseline and have a contractual arrangement for capturing the energy value for customers. This is probably not an issue in most of the Midwest ISO states.

IV.A.4 Overall Pros and Cons

Dynamic pricing is economically very efficient. It helps to relieve tight market conditions and enhance market competitiveness even if it is merely *responsive* (*i.e.*, not integrated) rather than actively participating in energy markets. Dynamic pricing can potentially incorporate a large amount of load into energy markets (it addresses more end-uses than direct load control) but only if states are willing to offer dynamic rates. Finally, some of the enabling technology has the ancillary benefit of providing good information that inspires energy efficiency. However, in contrast to approaches that provide active participation in the market via the “demand curves” or “supply curves” approaches, this “no curves” approach suffers from lack of full integration as discussed in Section III.

IV.B RESPONSIVE DLC BY LSEs NOT ACTIVELY INTEGRATED INTO RTO ENERGY MARKETS (A “NO CURVES” APPROACH)

IV.B.1 Basic Description

As with dynamic pricing discussed in Section IV.A above, LSEs can use their DLC programs to modify their demand without bidding their willingness to trigger load reductions as price response demand. PSEG, BG&E MD, Pepco MD, and Delmarva DE are examples of utilities in PJM with direct load control programs that reduce load in response to high energy prices (not

just in emergencies). Some utilities within MISO do this as well,²⁵ to the extent that this is allowed under the contractual arrangements of the DLC programs. They have been doing this even before the RTOs were established. In all of these programs, the triggering event is when real-time prices exceed a certain threshold (*e.g.*, \$280/MWh in Pepco). Most have a limited number of calls and no per-event payments except in PSEG. These programs were developed largely as enhancements to legacy reliability DLC programs. Like the reliability programs, they target easily-controlled end-uses including residential and commercial A/C & water heaters, commercial lighting, industrial support load, and some process load.

IV.B.2 Enabling Elements at the RTO Level

There are no enabling elements except transparent pricing. The RTO must learn to incorporate behavior into its short-term load forecasts. Note that no baseline is needed because the LSE is using DLC only to reduce its net load rather than selling load reductions as supply nor are the demand bids clearly affected. However, most DLC resources also seek a capacity credit, which does require defining a baseline and having to measure and verify load reductions.

IV.B.3 Enabling Elements at the State/Utility Level

Only minor control equipment is necessary, but interval meters can enhance the ability to measure and verify participation. The larger barrier is LSE incentives and capabilities. Incentives can be addressed through decoupling the fixed-cost components of retail rates from volumetric sales of energy and demand, rate-basing of investments, and other shareholder incentives. Where LSEs lack the necessary expertise, they can contract with a CSP on a fee-for-service basis. Deregulated states in which utilities outsource the provision of supply for standard offer service have additional barriers, but these are unlikely to be an issue in the MISO states.²⁶

²⁵ Detroit Edison and Cinergy/Duke are two examples.

²⁶ In SOS states (described above), there is no direct way for utilities to capture the value of load reductions; the wholesale suppliers capture the value. Maryland and Delaware allow the electricity distribution companies (EDCs) to capture value (on behalf of customers) from SOS suppliers by requiring them to supply gross load to the EDC. PJM pays the EDC the real-time price for the difference between its supplies (=gross load) and metered load (=net). Hence, a baseline is needed even though load reductions are not actually being offered as negawatts into the ISO markets. This complication might be unnecessary if customers faced dynamic pricing.

IV.B.4 Overall Pros and Cons

DLC from existing reliability programs can be converted relatively easily into a more flexible resource that is responsive to economic signals. However, there are usually very limited run-hours, and few end-uses other than central air conditioning that are targeted. Moreover, most DLC programs give the customer no opportunity to adjust consumption dynamically based on its preferences, which is clearly less efficient than dynamic pricing.

IV.C DYNAMIC PRICING ACTIVELY INTEGRATED INTO RTO MARKETS AS “DEMAND CURVES” BID BY THE LSE

IV.C.1 Basic Description

For markets that have demand-side bidding, the “demand curves” approach offers better integration than the “no curves” approach addressed in Section IV.A above. The Midwest ISO allows demand side bidding in its markets. Of course, the requirements for the RTO are greater than with the “no curves” approach. As already mentioned in Section II of this report, in the Midwest ISO, WPS has developed an innovative and successful approach to dynamic pricing for its largest customers. WPS exposes its customers to real-time prices (RTP) in the top 300 hours unless their price responsive demand (PRD) bids clear in day-ahead, as follows:

- WPS bids its day-ahead forecast for each customer (aggregated) into the day-ahead market as a PRD bid at a specified threshold price. If the day-ahead price is below the threshold, the customer consumes as much as it wants at the retail rate. If the day-ahead price is above the threshold, the customer pays RTP on all consumption in that hour, which induces load responsiveness when prices are high.
- The number of hours with real-time exposure is limited to 300 annually, and the threshold is set in one of two ways selected by the customer: (a) set monthly at a level considered “scarcity pricing” or (b) varied daily by WPS in order to try to hit 300 calls exactly by the end of the year.
- Customers have a “buy-through” option to specify a quantity and price at which they are willing to buy energy day-ahead. If day-ahead price is below the threshold, they still pay only the retail rate. If the day-ahead price is greater than the threshold price but less than the buy-through price, the customer pays the day-ahead price on its buy-through quantity

and pays the RTP (or gets paid RTP) on all deviations. If the day-ahead price is greater than the buy-through price, all consumption is priced at the RTP.

- Customers are also assessed a small adder to cover ISO imbalance penalties on top of the RTP (for deviations from DA schedules).
- In return, customers enjoy a lower rate, reflecting truncated costs and a reduced risk premium from WPS. WPS adjusts only the demand charge, but other variants are possible. Under WPS rates, all real-time energy payments are incremental, requiring customers to forecast likely costs in their budgeting processes. A possible improvement would be for the utility to charge an expected cost of real-time energy, subject to a true-up.
- This approach achieves dynamic pricing for approximately 300 MW of load, which is roughly 15% of WPS's total load.

IV.C.2 Enabling Elements at the RTO

The major market design element is allowing price responsive demand to participate in day-ahead market clearing, which Midwest ISO has already implemented. There must, of course, be a match between program characteristics such as timing and response, as discussed in Section V. In addition, the RTO needs to be able to accommodate significant imbalances when the customers' load does not clear day-ahead but then appears in real-time. Assuming real-time follows the "no curves" approach, this results in imbalance revenue sufficiency guarantee charges, as it does for any market participants (in addition to settling incs/decs at the real-time price), but these will usually be a small fraction of the price of energy. These imbalances pose no operational problems as long as the RTO anticipates the (increased/reduced) load in its short-term load forecasts used for unit commitment and dispatch purposes. When dynamic pricing is first implemented, neural network-based, short-term forecasts might be less accurate (if spot price has not been a variable affecting consumption in the past), and excess unit commitment and operating reserves might be needed. Eventually, short-term forecasts should become no less accurate than they are under fixed rates.

IV.C.3 Enabling Elements at the State/Utility Level

This type of program should be welcomed by state commissioners. It creates a substantial amount of economic DR in the highest-priced periods without exposing customers to market prices the other 97% of the time (hence largely avoiding exposure to a California-like crisis or Katrina-like spike in fuel prices).

IV.C.4 Overall Pros and Cons

The example of WPS shows that this is a promising approach for larger customers because it achieves demand responsiveness to the real-time price in the highest-priced hours, while also providing the RTO with useful information regarding demand (*i.e.*, “buy-through” DA demand bids are firm, and the rest is responsive to RTP). This “demand curves” approach is superior to non-integrated dynamic pricing programs that have limited high-priced hours because participation in the day-ahead market is used to select the critical days. It also avoids the awkwardness and transactions costs by both the LSEs and RTOs of “supply curve” approaches, which require defining a hypothetical baseline and implementing funding mechanisms.

The WPS program may also provide an example of an approach for incorporating dynamic pricing with smaller customers since dynamic pricing programs such as CPP face some skepticism as to whether they could be incorporated into RTO programs under either the “demand curves” or “supply curves” approaches. To use CPP as an example, under either the “demand curves” or “supply curves” approaches, the LSE or CSP would set a reservation price through its bid to reflect the value of calling a critical peak day. This would allow elasticity to play directly in the RTO market and perhaps let demand set the price.

One objection that was voiced about this in our interviews is that the amount of load reduction is uncertain. While this is true because load reductions due to calling critical peak events will depend on the usage ahead of time, the available evidence from the California Statewide Pricing Project is that the variance is limited. Table 3, below, shows that the variability in response is likely limited to no more than plus or minus 6-18 percent of the mean reduction, depending on the rate structure. For example, for 100 MW of *expected* reduction under the CPP-F-2003 rate, there would be a 95% probability that the reduction would be between 91 MW and 109 MW.

TABLE 3: VARIATION IN IMPACTS FROM VARIOUS CPP RATES

	Lower than the Mean Reduction	Mean Reduction	Higher than the Mean Reduction
CPP-F-2003	-9%	13%	9%
CPP-F-2004	-11%	14%	11%
CPP-V/Track A	-18%	16%	18%
CPP-V/Track C	-6%	27%	6%

1-The CPP-F rate had a fixed period of critical peak and day-ahead notification. CPP-F customers did not have an enabling technology.

2-The CPP-V rate had a variable-length of peak duration during critical days and day-of notification.

3-Two-thirds of Track A customers and all Track C customers had enabling technologies.

Moreover, there are detailed issues such as timing, location, and imbalance that need to be settled for integration of dynamic pricing. Possible program design at the end-user program level would enhance the usefulness to the Midwest ISO. For example, the ability to call critical events in geographical blocks could ameliorate locational issues. This could also enhance the ability to better price DR in smaller increments rather than as an all-or-nothing block.

IV.D LSE DIRECT LOAD CONTROL INTEGRATED INTO RTO MARKETS (A “SUPPLY CURVES” APPROACH)

IV.D.1 Basic Description

In the “supply curves” approach with the LSE acting as the market participant, the LSE offers “negawatts,” *i.e.*, verifiable load reductions from a baseline, as supply for which it is paid by the RTO. ComEd’s DLC Residential AC cycling program (60,000 participants) offers negawatts into PJM’s real-time market; the amount that clears gets paid as supply.

IV.D.2 Enabling Elements at the RTO Level

LSEs with DLC could schedule negawatts into day-ahead energy markets, but doing so is not common purportedly because LSEs do not want to take on the associated financial obligation. DLC more commonly participates only in real-time, with negawatts either self-scheduled or

dispatchable.²⁷ The RTO's commitment, dispatch, and real-time market clearing software needs to accommodate either self-scheduling or dispatchability, with the dispatch parameters similar to those of some generators. For example, the RTO's commitment and dispatch software must be able to consider a strike price and operating constraints, such as two-hour blocks with one-hour lead time in the ComEd program. However, the RTO need not enable the DLC resources to actually set the price in real-time because the DLC is unlikely to meet the requirements for doing so. None of the DLC in PJM has real-time telemetering, which the real-time market clearing software requires for price-setting; almost none has nodal pricing because most loads settle at the zonal price; PJM also does not consider the baseline from which negawatts are measured to be certain enough (until after the fact) to be eligible to set the price in real-time; and almost all DLC is block-loaded, which means that current market clearing software does not allow it to set the price.²⁸ Conceivably, program design at the end-user level and changes in how prices are calculated could overcome these difficulties and enable some large DR resources to set prices.

In order for the market to clear with adequate supply when DLC (or any approach) provides negawatts, the RTO must ensure that the short-term load forecast reflects the gross load, *i.e.*, with the estimated load reduction added to the net load. The need for the RTO to determine the amount of load reduction points to the greatest challenges with implementing "supply curve" approaches. All "supply curve" approaches require establishing a customer baseline load, M&V protocols, and settlement mechanisms. These challenges are described in Section V.

Settlement is simple from the RTO perspective if the LSE must pay for the gross load, as in PJM, but it is more complicated if the LSE pays for only its net load, as in ISO-NE. In that case, other LSEs must be charged some sort of side payment to fund LMP-based payments to the DR. If the LSE is not charged for the gross load, side-payments from other LSEs are needed even if there is no subsidy whereby the end-user saves its retail rate and receives the full LMP. PJM has eliminated its subsidy by limiting payments to DR providers to the LMP *minus* the retail rate, but

²⁷ Particularly in restructured states in which electric distribution companies (EDCs) are not responsible for supplying generation, the EDCs do not have a mechanism for recovering costs of that are incurred as a result of deviating from day-ahead obligations. Participation by DR in day-ahead energy markets might be more viable in most of the Midwest ISO than it has been in most of PJM.

²⁸ These factors have been barriers in PJM, but there may be ways around them.

ISO-NE and NYISO have not yet.²⁹ However, it should be noted that even PJM has some hidden subsidies for DR. There are system-wide costs of accommodating resources that are dispatched based on a zonal price instead of a nodal price. PJM also does not currently impose operating reserve penalties on imbalances from DR that shows up in real-time (such as that in ComEd’s program) without having cleared day-ahead. If generation without a day-ahead schedule shows up in real-time, it is charged a balancing operating reserve charge on 100% of its output (which typically amounts to \$0.25 to \$3 per MWh, roughly 1% of LMPs). PJM is considering revising its rules to treat DR the same as generation.

IV.D.3 Enabling Elements at the State/Utility Level

The state-level enabling elements are the same as for DLC under the “no curves” approach, described above. However, for DLC under the “supply curves” approach, the question of whether the LSE has limited annual calls on end-users becomes more important. Programs with limited calls cannot always offer throughout an extended period of high temperatures and tight market conditions. An attractive solution would be for DLC programs to have unlimited calls with opt-out provisions and per-event payments that make continued participation worthwhile.

IV.D.4 Overall Pros and Cons

Compared to “no curves” DLC, “supply curves” DLC has significantly greater M&V and settlement challenges, but it is more integrated into the market and provides advantages through better coordination of load reductions with market conditions and better conveyance of price signals, particularly if the DR can set prices.

IV.E IMPLEMENTATION BY CSPs SELLING NEGAWATTS INTO RTO MARKETS (A “SUPPLY CURVES” APPROACH)

IV.E.1 Basic Description

Curtailment Service Providers such as EnerNOC, Comverge, and Energy Curtailment Specialists are very active in PJM, NYISO, and ISO-NE in achieving load reductions at end-users, which they aggregate and sell into the RTO energy markets as “negawatts.” Almost all self-schedule or

²⁹ Determining the relevant retail rate might not be straight-forward, particularly in states with retail access.

bid their negawatts into real-time markets. Almost no CSP-based DR bids into day-ahead markets, apparently because customer baselines and willingness to respond are less definite a day in advance. However, Viridity is pursuing a concept that could involve day-ahead market participation (see below).

It should be noted that CSPs are beginning to participate in ancillary services (A/S) markets as well, where allowed (PJM allows DR to provide synchronized reserves, ISO-NE has done pilot programs, and Midwest ISO will allow DR to provide regulation, spinning, and supplemental reserves when the A/S market is implemented). Several CSPs reported that there is more value in providing A/S than providing energy because they get paid all the time and get dispatched very little. Providing A/S is especially attractive for arc furnaces and other end-users that are heating or cooling large masses of material because their thermal mass allows them to lose load for up to 30 minutes (the average dispatch interval in PJM was 14 minutes last year).

IV.E.2 Enabling Elements at the RTO Level

CSPs generally require the same RTO rules as other “supply curve” approaches described above: including negawatts in the unit commitment, dispatch, and market clearing; the need to establish a customer baseline with robust M&V protocols, the need to gross up the load forecast, and settlement mechanisms to compensate load reductions at the LMP (minus the retail rate to avoid a distortionary subsidy³⁰) and to make bidders whole if their LMP-based payments do not cover their offer costs (just like generation). The CSPs we interviewed particularly emphasized the need to accommodate many kinds of operating constraints regarding notification time, minimum and maximum run times, and limited numbers of calls. Doing so would make DR more comparable to generation, which also is able to specify many operating constraints (also, intermittent generation resources are similarly unable to offer their supply all the time).

³⁰ Compensating CSP load reductions by paying them the LMP minus the retail rate is not the only way to avoid subsidies. Another option is to pay the CSP the full LMP but bill back that payment to the LSE serving the load that curtailed. This is effectively billing the LSE for its gross load. The LSE will lose revenue (at the retail rate) unless it charges the retail customer on a gross load basis. The RTO/ISO need not get involved in these retail transactions, which are the purview of the LSE and its state regulators. Involving the RTO/ISO with tracking retail rates in the settlement system could create significant complications.

CSP-based DR that is not under direct load control has one characteristic that is not comparable to generation: individual assets have high non-performance risk because the customer can usually opt not to undertake a load reduction. CSPs largely overcome this problem by aggregating many customers and offering less than 100% of their potential reductions. If pre-scheduled reductions do not materialize, the amount of negawatts appearing in real-time can be a surprise. This can increase the need for operating reserves, and the associated costs should be charged to CSPs with imbalances, in addition to having to settle imbalances at the real-time price.

RTOs could potentially increase the value of CSP-based DR by requiring the participating customers to be dispatched and settled at nodal prices. This would allow DR to ameliorate rather than exacerbate intra-zonal transmission constraints. However, even if states allowed this, it could pose a challenge to CSPs in being able to aggregate across many customers, which helps them manage the risk that any particular asset does not perform. It might make sense to use nodal pricing only for customers above a certain (large) size. It should be emphasized, however, that even if DR is nodally dispatchable and able to put downward pressure on prices, it lacks the real-time telemetering, quantity certainty, incremental/decremental dispatchability to be able to set prices in real-time.

IV.E.3 Enabling Elements at the State/Utility Level

Enabling elements at the state/utility level are generally the same as already described above for “demand curves” or “supply curves” DLC, except that the state must also allow CSPs access to its customers. There is some dispute about whether CSPs constitute “retail access,” so states need to clarify that CSPs are welcome. States also need to mandate that utilities provide CSPs with the necessary customer meter and settlement data.

IV.E.4 Overall Pros and Cons

CSPs account for the majority of new DR in PJM, NYISO, and ISO-NE. Lacking the disincentive that prevents utilities from undertaking measures that reduce their customers’

volume (energy and demand), CSPs have been innovative and aggressive in designing detailed load reduction protocols for medium and large C&I customers.³¹

The largest cons with enabling the “supply curves” approach for CSPs (or LSEs) are the need to establish a customer baseline and the associated M&V challenges. In addition, the RTO would incur costs to accommodate CSPs in settlement process (including having to identify the relevant retail rate if the CSP is paid the LMP minus the retail rate; the alternative is to pay the CSP the full LMP and charge the LSE for the full gross load, which the LSE could charge back to the customer). There might also be duplication of LSE systems (and costs) in settlements and billing. Another con is the potential need for coordination between the LSE and the CSP regarding the LSE’s day-ahead purchasing to cover the DR resources’ loads and coordination regarding the LSE’s long-term resource planning efforts to cover the DR resources’ loads.

Notwithstanding the cons outlined above, CSPs could provide at least a bridge for several years to a long-run first-best solution in which states implement dynamic retail rates and eliminate much of the need for CSPs to enable economic DR.

IV.F IMPLEMENTATION BY DIRECT WHOLESALE CUSTOMERS AND RTOs (A “SUPPLY CURVES” APPROACH)

IV.F.1 Basic Description

The largest industrial end-users that are direct wholesale customers are able to provide DR directly to the RTO. For example, Alcoa’s 600 MW Warrick Operations in Indiana reduces its smelting load when the real-time price exceeds a certain threshold. It becomes a net seller of electricity and earns the real-time LMP for its sales. That facility has also made an investment in real-time telemetering and will allow the Midwest ISO to take 10 MW of regulation by controlling 10 MW of its load. Regulation is the most valuable A/S product, and presumably Alcoa will get more value by providing regulation all of the time rather than providing load reductions into the energy market a handful of times per year.³²

³¹ As discussed above, this does not seem to be related to “double payment.” High levels of participation in PJM have continued despite discontinuation of double payment. See Figure 6.

³² Such technology could also enable similar end-users to provide negawatts (or load reductions on the demand side) that are able to set the price, although we do not know of any instances of this. For example, PJM has zero MW of DR that are able to set the price in real-time.

Since some of the largest users face dynamic rates at least on the margin, there may not seem to be a need for them to offer negawatts as supply or load reductions on the demand side in order for them to capture the value of their ability to reduce load. Providing negawatts could give DR the same access to make-whole payments as generators for which the market price does not cover their bid-based commitment costs, including startup, minimum load, shutdown, and hourly curtailment costs.

IV.F.2 Enabling Elements at the RTO Level

The RTO-level enabling elements for providing negawatts are the same as for CSPs and integrated DLC. In addition, supporting participation in A/S or participation in energy markets with real-time price setting capability requires cooperation with the RTO and the end-user regarding installation of the right equipment, clear establishment of baselines, and communications and dispatch protocols.

IV.F.3 Enabling Elements at the State/Utility Level

Allow the largest customers to become direct wholesale customers.

IV.F.4 Overall Pros and Cons

This approach is complementary to the other approaches, and it makes sense for the RTO to pursue it. However, one significant barrier is that large customers served by vertically integrated utilities typically pay retail tariffs based on embedded costs that are lower than the market prices, thus they have no incentive to give up that advantage. This is arguably the biggest impediment to large industrials choosing to be their own LSEs.

IV.G SUMMARY

Dynamic pricing is the most efficient approach with the greatest long-term resource potential, but except for a few leading programs and some pilots, it is only slowly beginning to be implemented. The barriers to DR, especially dynamic pricing, include: (1) state reluctance to expose all but the largest customers to volatile prices; (2) and lack of interval metering and

communications systems to provide interval data and two-way communication, especially among small customers.

Regarding the barriers to dynamic pricing, they are beginning to dissolve: state regulators are becoming increasingly comfortable with the idea. The topic has been featured prominently at several meetings of the NARUC and is receiving active consideration at professional and trade conferences, seminars and workshops around the country. In addition, utilities now have an incentive to implement dynamic pricing because it provides the means with which to justify their AMI investments.

In the absence of widespread dynamic pricing, various wholesale programs have been developed to enable the marketing of negawatts through the “supply curves” approach as a “no lose” way to expose customers on fixed rates to market prices. Such approaches include LSEs offering DLC negawatts into RT markets, CSPs offering DLC (and indirectly controlled) negawatts into RT markets as self-schedulable or dispatchable in RT, similar for large wholesale customers. Day-ahead participation in these programs is rare.

In order to facilitate the “supply curves” approach, RTOs must establish programs or market designs that provide for incorporation of DR negawatts into their scheduling, dispatch, and settlement systems, comparable to the treatment of generation. Issues include the similarity of DR to block-loaded combustion turbines. Moreover, no DR currently sets real-time prices³³ in other RTOs due to lack of telemetry, zonal prices, and customer baselines that are uncertain until after the fact. An appropriate baseline methodology must be implemented, and a funding mechanism (discussed in the next section) must be developed. However, as expanded upon in the next section, unless customers have a way to take title to their baseline usage, negawatt approaches have the disadvantage that baselines are subject to gaming and uncertainty, and side-payments from other customers to fund payments to negawatts are questioned if baseline is uncertain.

³³ The NYISO does allow emergency DR resources to set real-time LMPs during emergency events despite the lack of telemetering. They do this by estimating the DR response and truing up after the fact when the meter data become available.

V. SPECIFIC RTO ISSUES IN DETAIL

This section covers several particular RTO level issues in detail:

- Payments and potential subsidies
- Measurement and verification
- The ability of DR to set energy market prices
- The cost of RTO DR programs

V.A PAYMENTS AND POTENTIAL SUBSIDIES

Payments for DR at the RTO level is a feature of the “supply curves” approach for integrating DR into an RTO. One objective of RTO-administered economic DR programs using supply curves is to correct for the perceived market failure that retail customers are not exposed to and hence do not adequately respond to hourly wholesale electricity prices. The effect of this perceived market failure at the retail level is that the market demand within the RTO market mechanisms is very inelastic, and therefore markets function at higher prices. RTO-administered DR programs establish an accounting mechanism that fund payments to DR participants that should, at least in theory, incent program participants to consume electricity more efficiently.

Funding payments for participation in economic DR programs is an RTO-level market design question under the “supply curves” model.³⁴ It is an issue because it requires that DR be treated as a generation-like resource that is disconnected from load bids. Hence, because LSEs and their customers pay only for their actual net usage, “selling” load reductions is basically reselling something that neither the customer, nor their LSE or CSP, has bought (unless the RTO mandates that LSEs pay for their net usage plus supply-side load reductions as in PJM). Compare this to the “demand curves” approach where, for example, an LSE can bid a gross load of 1000 MWh, and if 100 MWh of DR gets deployed, the LSE is in effect charged for 900 MWh. The LSE is charged for the gross load and credited for the DR, whereas if the LSE is charged only for the net in the “supply curves” model, this raises insufficient funds to pay for the DR without an uplift payment. Other RTOs have covered this shortfall through uplift payments

³⁴ One could, of course, imagine payments to LSEs for economic DR. The issues under that scenario remain, but in addition there may be issues of complicating the incentives an LSE has to respond to market prices.

imposed on all customers in the zone or in the RTO. Another possible approach would be to charge only the host LSE, which is the approach adopted by the Midwest ISO and supported by various stakeholder groups.

All RTOs that have enabled the “supply curves” model provide or have provided substantial payments to DR participating in energy markets beyond those in the “demand curves” model. The payment mechanism works as follows: recall that economic DR programs under the “supply curves” approach provide incentive for fixed-rate customers to curtail end-uses that are of lesser value than the spot price for energy, as if the customers were exposed to spot prices. From the wholesale market perspective, the value of one MWh of load reduction is identical to that of a one MWh increase in generation, equal to the LMP. If the customer paid the LMP for each MWh consumed, the savings to the customer would also equal the LMP. However, the situation is somewhat different from the retail perspective. Compensating DR at the full LMP actually provides the customer with more than that in total savings, since they also avoid paying their retail rate on the reduced load (it is as if they are reselling at a high price without ever buying the energy in the first place). Therefore, many argue that retail DR customers should receive only the market price *minus* the retail rate they avoid paying, in order to receive the same price signal as direct wholesale market participants.³⁵

Figures 4 and 5 show the payments for energy and load reductions between the end-user, LSE, CSP, and the RTO, in the “supply curves” model, with the LSE and CSP as market participants, respectively.³⁶ As shown in Figure 4 under a version of the “supply curves” model, the LSE effectively pays for its net load (G-LR) in the RTO wholesale market. The payment for the load reduction is the market price (LMP) less the retail rate (RR), which the RTO funds from a charge equal to the DR payment that is allocated to the LSE. The end-user pays the retail rate for its net load, and receives a DR payment that is likely to be less than the LMP minus the retail rate for

³⁵ Others argue that RTOs should not be involved in any retail rate schemes, and not deal at all with retail customers, even indirectly, as the RTO markets are wholesale markets, and as such should credit or charge LMP to wholesale customers only. According to this view, the CSPs, LSEs, retail customers and the state Commissions should sort out the distribution of wholesale charges and credits amongst themselves.

³⁶ In the chart, the arrows indicate the direction of payments. Note that there is an alternative model in which the CSP would receive the full LMP and the LSE would be charged (and would charge the end-user) for the gross load.

every MWh of load reduction, since the LSE must keep some of the DR payment from the RTO to recover its administrative costs.³⁷ Figure 5 illustrates the CSP-enabled “supply curves” model.

FIGURE 4 – DR PAYMENTS IN THE “SUPPLY CURVES” MODEL WITH THE LSE AS THE MARKET PARTICIPANT

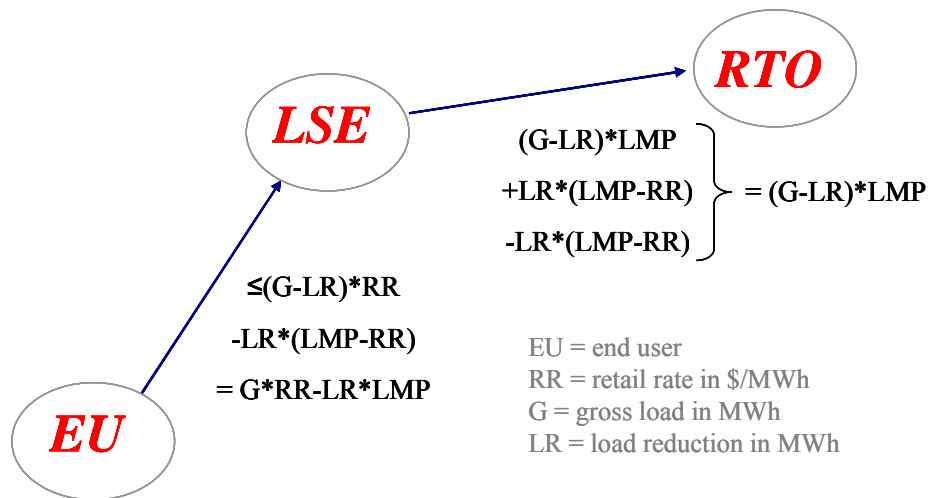
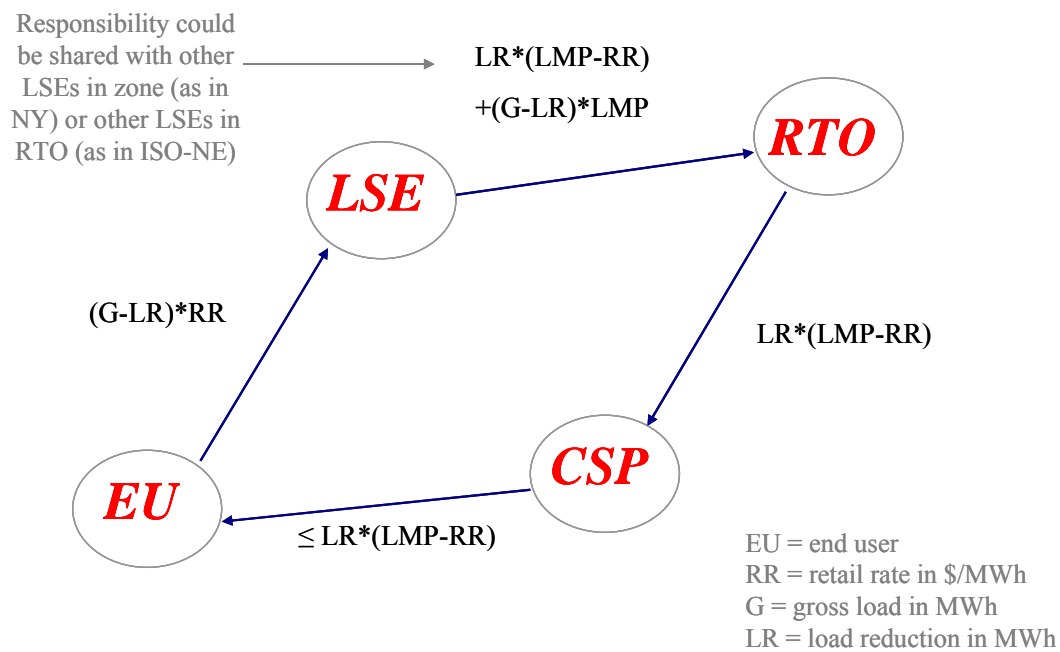


FIGURE 5 – DR PAYMENTS IN THE “SUPPLY CURVES” MODEL WITH THE CSP AS THE MARKET PARTICIPANT



³⁷ Or, perhaps, recover it in an uplift across all customers.

Note that the retail rate must be deducted from the LMP in order to provide efficient price signals to the end-users and avoid “double payment” for reductions. If load reductions were paid the full LMP, then by reducing its load, a customer would be paid the LMP *and* would avoid paying its retail rate, while losing the value that it put on consumption. If that value is greater than the LMP, but less than the retail rate plus the LMP, then an inefficient reduction in load would occur. For example, suppose the value that a customer puts on consumption from the grid is \$250/MWh (for instance, by having a backup generator that can run at that cost). If the retail rate is \$120/MWh, then the customer would break even with an offer of \$130/MWh. If the LMP is \$140/MWh, the offer would clear. However, it is inefficient for the customer to reduce consumption and run their generator, because they could have bought power off of the grid. The result is a societal loss of \$130/MWh.³⁸

In practice, in all RTOs where the CSPs are active, some or all DR receives or has received subsidies including some form of “double payment.” Common justifications for subsidies include: (1) the need to accelerate the development of the DR industry so that DR can reach its economic potential more quickly; (2) the presence of positive externalities in markets with market failure, such as the price-mitigating effect of DR, especially in load pockets during peak periods; (3) the existence of state, utility, customer or market-level barriers that prevent DR from taking advantage of the same market opportunities as generation (*e.g.*, participation in A/S markets); and (4) end-use customers have to share some of the DR payments with their CSP or LSE. (However, CSPs tend to pass most of the energy price to their customers while keeping a larger share of the capacity value).

The efficiency of subsidies depends on the value that the market as a whole receives from DR in the form of reduced prices or increased reliability. The difficulty of measuring the benefits and the ability to compensate losers if subsidies are imposed are very difficult, however. Subsidies should only be used if: 1) one of the justifications listed above applies; and 2) the total benefits of DR outweigh the total cost of funding the subsidies, but it is debatable whether total benefits should include only the changes in consumer surplus or if they should also include changes in

³⁸ This example was taken from *The Future of Price Responsive Demand in ISO New England*, ISO New England and The Brattle Group, November 5, 2008.

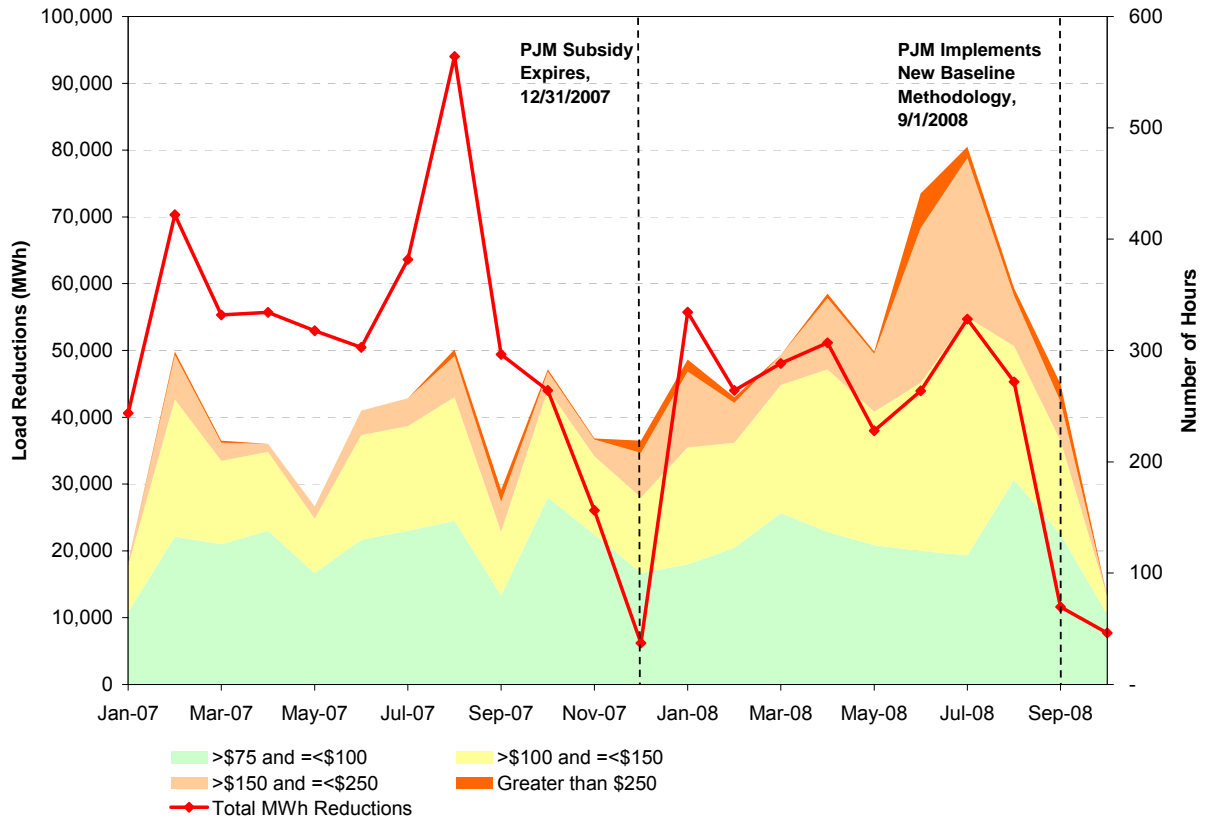
producer surplus (as in a total resource cost test). Regarding consumer surplus, a *Brattle* study conducted for PJM and MADRI last year showed that non-participating LSEs and their customers benefit from lower prices that far exceeded the energy payments to DR participants, based on an analysis conducted with a short-run equilibrium model. However, as the study states, lower energy prices can raise capacity prices; and to the extent that DR reduces the amount of installed generation capacity (and the type) online, energy prices can eventually increase.³⁹ In the long-term, energy and capacity prices will change as a result of DR, but probably not as much as a short-run equilibrium model indicates, except in areas with market power. Actual benefits might be far greater under extreme conditions or in load pockets where there are barriers to entry of generation. In such situations, DR increases reliability and competitiveness, and hence subsidies that reward CSPs and other forms of DR might be justified.

ISO-NE and NYISO subsidize DR by paying it the full amount of the day-ahead or real-time LMP without deducting the retail rate. PJM used to do the same whenever the LMP exceeded 75 \$/MWh.⁴⁰ However, PJM eliminated its subsidy on December 31, 2007. It now pays economic DR the wholesale price (LMP) less the retail generation and transmission charges (these payments are funded by the host LSE, as depicted in Figure 5). Figure 6 below shows participation in the PJM economic DR program before and after the adjustment of the payment to DR from the LMP to the LMP minus the retail rate. While program participation appears to have decreased, the causes for this are not obvious, and clearly the reduced payment has been high enough for DR to continue to participate at significant levels.

³⁹ *Brattle* conducted a subsequent study for Pepco Holdings, Inc. (PHI) in which the duration of DR's energy price impacts depends on the rate at which generation suppliers respond to the introduction to DR. In scenarios where suppliers respond slowly, the net present value of customer benefits from reduced energy prices is significant but still smaller than the capacity value of DR.

⁴⁰ In NYISO's Day-Ahead Demand Response Programs, DR cleared in the day-ahead market receives a rebate from the NYISO as an incentive for the curtailed amount of load priced at day-ahead LBMP, without making any adjustments for the customers' retail rate savings. In ISO-NE, DR customers receive the full LMP without adjustment for their savings in retail rates, although ISO-NE is reconsidering this approach.

FIGURE 6 – PJM ECONOMIC DR PROGRAM PARTICIPATION



V.B MEASUREMENT AND VERIFICATION

Measurement and verification (M&V) refers to the set of tools and methods used to measure and verify load reductions in order to estimate the impact of DR. M&V concerns the RTO primarily in the case of load reductions that are bid as a positive resource (“supply curves” approach), but not for reduction from a demand bid (“demand curves” approach). The Midwest ISO has not had to address M&V issues with regard to DR participation in energy markets – when the LSE bids in a load reduction to be offset against its demand bid, such that it is billed for the actual net consumed, the Midwest ISO does not need to measure or verify the reduction, although the LSE must. However, the Midwest ISO has already addressed a number of M&V issues for DR in A/S markets and in its emergency demand response program (EDR). For example, the A/S proposal recently approved by FERC requires the DR provider to submit five-minute demand forecasts as a baseline for measuring performance. Such a short-term baseline is much more difficult to

game than the methodologies currently used in other RTOs to define baselines from which load reductions are measured for settlement in energy markets.

Measurement and verification protocols may affect the willingness of DR to participate in energy markets and may create opportunities for gaming and/or for load reductions that occur for reasons other than responding to wholesale market prices. This section will discuss (1) simplicity vs. accuracy of M&V; (2) baseline definition and gaming; and (3) equipment requirements.

V.B.1 Simplicity vs. Accuracy

It is important to balance the accuracy of performance measurement with the simplicity of calculations. Determination of compliance with a dispatch instruction must be transparent and relatively simple. Complex or unclear rules may discourage participation by DR. For example, ERCOT's Balancing Up Load (BUL) program, in which DR can bid to provide balancing energy, failed to enroll any load since its inception in 2003. The PUCT attributed the complicated load impact estimation methodology as one factor behind this failure.⁴¹

Another issue is whether M&V is performed on an individual resource or a CSP/LSE portfolio basis. Many CSPs and LSEs may prefer performance evaluation on a portfolio basis because it allows them to compensate underperformance of one of their resource by the over-performance of another resource.

V.B.2 Baseline Definition and Gaming

A combination of economic conditions and RTO business rules can give rise to gaming opportunities. For example, in ISO New England's Day-Ahead Load Response Program (DALRP), days when a DR offer clears in the day-ahead energy market are excluded from the calculation of the baseline for the DR customer (this is done to exclude days/hours from the baseline calculations when load levels are artificially low due to curtailments).⁴² Gaming

⁴¹ PUCT DR Workshop presentation, December 8, 2006.

⁴² ISO-NE ISO New England Load Response Program Manual, Section 4.2.2.

purportedly arises because the baseline is not evolving sufficiently quickly as load conditions which can create an incentive for participants to temporarily increase load, then exclude subsequent days from the baseline calculation by engineering frequent (small) curtailments.

Until recently, DR was subject to a \$50/MWh minimum offer requirement (originally intended to restrict DR participation to peak hours). The rise in fuel prices resulted in market conditions when market prices exceeded this threshold most of the time, hence increasing the likelihood that DR bids above the minimum threshold cleared as well, causing many days to be excluded from the baseline. A recent ISO-NE analysis showed that, by making offers every day DALRP participants are able to engage in strategic behavior that overstated their respective customer baselines and received compensation for load reductions that did not in fact occur. By allowing customers to lock in their baseline for an extended period of time they could artificially inflate their load during the initial calculation period or keep the summer baseline level locked in during the winter months. The FERC-approved solution that ISO-NE implemented in February 2008 was to index the DALRP minimum offer price to ISO-NE's Forward Reserve Fuel Price Index using an implicit heat rate of 11.37 MMBtu/MWh, although some CSPs argued that ISO-NE should improve the CBL methodology rather than imposing a minimum offer price.

Similarly, PJM recently revised its CBL methodology because of suspected gaming.⁴³ In 2006, PJM noticed certain entities were claiming demand reductions under the economic DR program that would have been made regardless of the level of prices in PJM energy markets, indicating that the program was susceptible to gaming. The prior CBL method calculated the baseline as the hourly average of the five highest load weekdays out of the ten most recent weekdays, excluding holidays and event days.⁴⁴ Additionally, the prior method excluded days where the usage on non-event days was 75% or less of the average usage on non-event days. This method could potentially overstate the CBL, due to the exclusion of low usage days that were representative of the participant's normal usage and should have been included in the baseline. The revised method reduces the chance of overstating the CBL, by including a larger percent of

⁴³ Federal Energy Regulatory Commission, Docket No. ER08-824-000, June 12, 2008.

⁴⁴ Event day are classified as a day where the program participant's load reduction offer is accepted in either the day-ahead or real-time energy market.

the recent days (four out of the five most recent days) and excluding only those non-event days when the average usage on non-event days is 25% or less of the average usage on non-event days.⁴⁵

Baseline definition is one of the most difficult and contentious market design issues surrounding DR. More detailed analysis of best practices may be warranted if the Midwest ISO expects significant participation of CSPs through its DRR mechanism in the future.

V.B.3 M&V Equipment Requirements

RTOs usually require hourly interval meters for DR to participate in energy markets. Most DLC-enabled DR, however, lacks such metering equipment. In general, there is a tradeoff between participation and the quality of information that metering equipments provide. Establishing a more stringent metering requirement (*e.g.*, sub-hourly interval meters) provides better information for calculating a CBL, but is also likely to reduce participation as fewer DR resources will be able to meet those requirements.

Applying the same metering standards to DR as to generators may also be prohibitive for DR. For example, the 1-minute interval metering requirement in PJM's synchronized reserves market can exclude most loads, since most advanced meters are hourly or quarter-hourly. Statistical measures could be used to measure the performance of DR that is under direct load control by the RTO, utility, or CSP. Some RTOs (*e.g.* ISO-NE and NYISO) have addressed these barriers created by metering requirements by providing grants and rebates to DR that wants to participate in a program.

V.B.4 Measurement and Verification Conclusions

As can be seen from the discussion above M&V is a thorny and complicated issue for DR under the supply curves model with possibly significant transactions costs for the RTO, LSE, CSP, and

⁴⁵ Note that PJM's baseline is not a simple average of usages over the relevant days. A weather-sensitive adjustment may be applied to weather sensitive loads. The adjustment factor is based on an estimated relationship between hourly customer loads and the temperature-humidity index (THI) during recent, non-holiday weekdays. The baseline is adjusted upwards if the average THI during the event day exceeds the average THI during the five past days used in the baseline calculation.

perhaps the EDC. There are some efforts underway, however, to standardize M&V protocols. North American Energy Standards Board (NAESB) has proposed M&V wholesale standards that are out for public comment that will be considered by the WEQ Engineering Subcommittee, having passed out of the DSM subcommittee last month. It is important to emphasize that under either of the other two models this difficulty is not encountered. Under the demand curves or no-curves models, there is no need for M&V because the reductions in demand are reductions in a commodity to which the seller has title. The LSE simply pays for its net load.

V.C THE ABILITY OF DR TO SET ENERGY MARKET PRICES

Economic DR, *i.e.*, that which is called based on bids into the energy market, can set the energy market price only if DR is fully integrated into the RTO's market software and DR resources can meet all requirements for setting prices. PJM and NYISO have fully integrated DR into their market software. In these RTOs, bids in the supply curves approach submitted by economic DR participants are added directly to the supply stack together with generation offers. The RTO's market software evaluates each bid, and determines which generator and DR offers will be accepted. When a DR bid is accepted and scheduled, the LMP in that hour will be lower than it otherwise would have been. DR can set prices in DA, although little DR participates in the day-ahead market. Most DR participates in the real-time market, where the conditions for being eligible to set the market price pose a substantial barrier. For example, PJM requires DR resources to have real-time telemetry to be eligible to set the LMP, which can be prohibitively expensive for smaller DR. PJM also requires incremental/decremental dispatchability (versus block loading, which characterizes most or all DR), a definite quantity of load reduction relative to a clear baseline (whereas adjustments to weather-sensitive customer baselines are determined only after-the-fact), and nodal pricing (almost all DR is priced zonally). As a result, PJM does not have a single megawatt of DR setting the price in real-time, although several hundred megawatts are dispatchable.

ISO-NE has not fully integrated DR into its market clearing because of the high cost of required software upgrades. ISO-NE chose the less expensive "sequential clearing" approach, where DR bids are accepted or rejected based on day-ahead LMPs that are established purely based on generator bids. Since DR bids are excluded from market clearing, market prices are not fully

efficient because they will not always reflect the marginal cost of the lowest cost available resource, whether it be DR or generation. In addition, proceeding sequentially leads to over commitment and dispatch and hence, uplift costs. The bias in market prices may be especially acute during system shortage conditions.

PJM's and ISO-NE's experiences suggest that having a very large amount of DR able to set prices in real time may be infeasible, but it is important to enable at least some in order to avoid inefficient pricing. The Midwest ISO should at least enable customers with nodal pricing, real-time telemetry, and real-time inc/dec dispatchability to be able to set prices. The Midwest ISO is currently engaged in research to enable DR that must be block-loaded and that lacks real-time telemetry to set prices. (Our understanding is that the Midwest ISO already has substantially more load settling at nodal prices than PJM has).

V.D THE COST OF RTO DEMAND RESPONSE PROGRAMS

From a wholesale market perspective, the costs of the DR programs include the direct costs of program administration (*e.g.*, measurement and verification costs), the cost of integrating DR into the wholesale market software, and the payments or subsidies paid to program participants.

Direct administrative costs of RTO programs are difficult to estimate, and there is very little publicly available data on such costs. In 2005, PJM estimated the direct administrative costs of its economic program at \$70,000 or approximately \$0.50 per MWh of load reductions.⁴⁶ This was a decline in costs compared to the period 2002-2004, when the direct administrative cost of the economic program averaged about \$1 per MWh of load reductions.⁴⁷ These numbers suggest that the ongoing cost of administering RTO DR is modest relative to other types of DR program costs.

Fully integrating DR into wholesale energy markets may require information systems and software upgrades to manage DR registrations, real-time communication, meter data submittal,

⁴⁶ Since 2005, enrollment in the economic program increased by 30% and annual load reductions associated with DR in the economic program more than quadrupled.

⁴⁷ PJM Market Monitoring Unit, Report to the Federal Energy Regulatory Commission, Docket No. ER02-1326-006, Assessment of PJM Load Response Programs, August 29, 2006.

measurement and verification, and so on. The cost of DR integration may be substantial, and are likely to be the function of the unique legacy systems of the RTO. Some RTOs, such as ISO-NE, chose not to fully integrate DR into their wholesale markets due to the high cost. ISO-NE estimated that a full integration of DR using an integration clearing approach would cost between \$4 million and \$7 million.⁴⁸ ISO-NE chose to implement a sequential clearing approach under which DR resources cannot set the market price. The estimated cost of implementing this approach was \$585,000.

A feature of RTO DR programs under the supply curve model is a payment mechanism to compensate consumers on fixed retail rates for load reductions that benefit the wholesale energy market. Table 4 below shows the total compensation, excluding any capacity payments, to DR resources that were activated during emergencies or as part of an economic DR program in ISO-NE, NYISO, and PJM during 2007. Payments for each MWh of load reductions range from \$76 in PJM to \$106 in NYISO.⁴⁹ The overwhelming majority of payments are paid to economic DR which is responsible for the majority of annual load reductions.

⁴⁸ Compliance Filing of New England Power Pool Participants Committee and ISO New England, Inc., FERC Docket No. ER05-627-000, February 18, 2005.

⁴⁹ Compensation for load reductions varies by RTO. For example, while DR providers in some RTOs receive the full LMP for a MWh of load reduction, those in PJM receive the LMP less the generation and transmission component (G&T) of the customer's retail rate. Prior to 2008, PJM paid the full LMP for load reductions when LMP exceeded \$75/MWh, which provided an effective subsidy to DR in the amount of the generation component of the retail rate. PJM estimates that the cost of such subsidies ranged from \$4 to \$28 per MWh during the 2002-2005 period.

TABLE 4: RTOs' PAYMENTS TO DR RESOURCES

Program	Note	ISO-NE	NYISO	PJM
Note		[1]	[2]	[3]
RTO Emergency/Reliability (\$ in 2007)	[A]	246,756	109,107	878,828
RTO/ISO Economic (\$ in 2007)	[B]	18,644,776	365,862	45,173,237
Annual Demand Response Reduction (2007, GWh)	[C]	235	5	610
DR Payment per MWh of Load Reduction (\$/MWh)	[D]	80	106	76

Sources and Notes:

[1A]: ISO-NE, 2007 Annual Markets Report; \$232,637 for RT reliability program load reductions, \$14,119 for RT profiled response; Tables 8.5 and 8-6.

[1B]: ISO-NE, 2007 Annual Markets Report; \$16,956,464 for DALRP reliability program resource, \$69.068 for DALRP RT price-response resources, and \$1,617,243 for RT price-response load reductions; Tables 8.5 and 8-6.

[1C]: ISO New England, 2007 Annual Markets Report, June 6, 2008, Table 8-3

[2A]: NYISO, Reports on Demand Side Programs, New Generation, and the ICAP Demand Curves under ER01-3001, et al, filed with the FERC on January 15, 2008; Tables 8 and 11.

[2B]: NYISO, Reports on Demand Side Programs, New Generation, and the ICAP Demand Curves under ER01-3001, et al, filed with the FERC on January 15, 2008; Tables 17.

[2C]: New York ISO, 2007 State of the Market Report, p.188; 4,150 MWh in day-ahead program, 245 MWh in TDRP.

[3A]: \$34, 454,412 in total capacity credits for June-December 2007, and \$878,828 during emergency activation on August 8, 2007; PJM 2007 State of the Market Report, Tables 2-88 and 2-89

[3B]: 2007 PJM State of the Market Report, Table 2-92

[3C]: PJM, 2007 State of the Market Report Volume 2: Detailed Analysis, March 11, 2008, p.100 and Table 2-88.

[D]: $((A)+(B))/[C]$

VI. COMPARISON OF THE MIDWEST ISO TO OTHER RTOS

VI.A INTRODUCTION

The following sub-sections discuss the amount of existing DR resources in the Midwest ISO footprint compared to other RTOs. Based on the number of megawatts enrolled as DR, or the amount of DR deployed during peak periods, the level of DR within the Midwest ISO looks similar to that in other RTOs (at least, as a percentage of total load taking into account the amount of self-generation). However, we identify the following potential gaps in the Midwest ISO's DR participation:

- Most of the DR in the Midwest ISO is emergency-type, with relatively little economic DR participating in energy markets;
- There is very little DR of any type in some areas within the Midwest ISO, suggesting that such areas may be behind their potential (or it suggests that the potential may not be there, the states have decided it is not cost-effective, or a combination of all of the above); and
- The fact that the Midwest ISO does not yet have CSPs, which have played a major role in developing DR in other RTOs, suggests that more DR could be developed.

VI.B INTER-RTO COMPARISON OF EXISTING DR RESOURCES

This section provides an overview of existing DR programs and their impacts on peak load. Table 5 below summarizes RTO-administered DR programs in wholesale markets in six RTOs with significant DR presence (PJM, NYISO, ISO-NE, ERCOT, MISO, and CAISO). As Table 5 shows, the range of DR programs offered and the opportunities to participate in wholesale markets varies significantly by RTO.⁵⁰

⁵⁰ See "Harnessing the Power of Demand, How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets," Markets Committee of the ISO/RTO Council, October 16, 2007.

TABLE 5: DR PROGRAMS AND PARTICIPATION IN RTO MARKETS

DR Program Market Participation	PJM				NYISO			ERCOT		
	ELRP Full [1]	ELRP Energy Only [2]	ELRP Capacity Only [3]	Econ LRP [4]	EDRP [5]	ICAP/SCR [6]	DA DRP [7]	EILP [8]	BUL [9]	LAAR [10]
RT Energy Market				◆					◆	
DA Energy Market				◆			◆			
Emergency	◆	◆	◆		◆	◆		◆		
Capacity Market	◆		◆			◆				
Ancillary Services				◆			◆			◆

Key	Existing participation option	◆	Proposed or Not Yet Active	◇
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Notes:

[1]: Emergency Load Response Program - Full Option

[2]: Emergency Load Response Program - Energy Only Option

[3]: Emergency Load Response Program - Capacity Only Option

Applies to ILR (Interruptible Load for Reliability) which receives capacity payments but does not bid into the capacity auction.

(PJM Manual 18: PJM Capacity Market; June 1, 2007; page 29 - 30)

[4]: Economic Load Response Program (Day-Ahead and Real-Time Energy Market)

[5]: Emergency Demand Response Program

[6]: Installed Capacity/Special Case Resource Program (reliability, capacity market)

[7]: Day-Ahead Demand Response Program (Day-Ahead Energy Market Only)

[8]: Emergency Interruptible Load Program (not yet active)

[9]: Balancing Up Load (Associated with balancing energy market)

[10]: Load Acting as a Resource (Associated with ancillary services)

DR Program Market Participation	ISO-NE					CAISO*			Midwest ISO*	
	RT DRP [11]	RT PRP [12]	RT PrRP [13]	DA LRP [14]	Direct Participation [15]	VLRP [16]	PLP [17]	Direct Participation [18]	EDR [19]	Direct Participation [20]
RT Energy Market			◆				◆			◆
DA Energy Market				◆						◆
Emergency	◆	◆				◆			◆	
Capacity Market	◆	◆						◆		◆
Ancillary Services					◇		◆			◇

Key	Existing participation option	◆	Proposed or Not Yet Active	◇
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[11]: Real Time Demand Response Program

[12]: Real Time Profiled Response Program

[13]: Real-Time Price Response Program

[14]: Day-Ahead Load Response Program

[15]: Currently as part of the Demand Response Reserve Pilot

[16]: Voluntary Load Reduction Program

[17]: Participating Load Program

[19]: Emergency Demand Response Initiative

[18]&[20]: Demand resources participate as supply in RTO markets, without any special provisions for DR.

* Current participation is by utilities only

Table 6 shows the total enrolled MW of DR at each RTO footprint in both RTO-administered and non-RTO programs. The enrollment numbers are presented by program type (*i.e.*, economic vs. emergency).⁵¹ DR enrollment in emergency programs dominates total enrollment in most RTOs, and at least in PJM and ISO-NE, it is the fastest-growing type of DR. For example, total enrollment of DR in PJM's emergency-type programs more than doubled between mid-2007 and mid-2008. This development mirrored the rapid increase in demand resource participation in

⁵¹ Note that some RTOs, such as the reliability and economic programs in PJM and ISO-NE, allow enrollment in multiple programs. Therefore the sum of enrollment numbers across all programs may overstate the total amount of demand resources participating in RTO markets.

PJM's capacity market, the Reliability Pricing Model (RPM), which was implemented in April 2007.⁵²

TABLE 6: ENROLLED AND REALIZED DR IN RTOS

	Program	Note	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
	Note		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Enrollment in RTO-Administered Programs	RTO Emergency/Reliability (2008, MW)	[A]	1,634	2,215	4,496	300	None	None	104 - 137 (Jul., '06)
	RTO/ISO Economic (2008, MW)	[B]	445	319	2,973			2,050 (Dec. '07; all for A/S)	
Enrollment in LSE-Administered Programs	Non-RTO Emergency/Reliability (2008, MW)	[C]	270	unknown	489 (summer '06)	8,600+	1,210 (spring '07)	unknown	1,763 (Oct., '07)
	Non-RTO Economic (2008, MW)	[D]			2,703 (summer '06)				1,043 (Oct., '07)
Realized DR RTO Only (except MISO, SPP, CAISO)	Annual Demand Response Reduction (2007, GWh)	[E]	235	5	610	unknown	unknown	4,637 ('06)	unknown
	Peak Hour Reduction (2006, MW)	[F]	597	948	1912 ('07)	2,651	70	DR not called on peak day	Approx. 2,066
	Reduction as a Percentage of Peak Load (2006)	[G]	2.1%	2.8%	1.4% ('07)	2.3%	Negligible % of peak	DR not called on peak day	4.1%

Sources and Notes:

[1A-B]: As of June 2, 2008; ISO New England Inc, Load Response Enrollment; http://www.iso-ne.com/genrtn_resrcs/dr/stats/enroll_sum/2008/lrp_as_of_06-02-2008.ppts
Total Emergency/Reliability DR = (1494.2 MW in RT 30-min)+(122.8 MW in RT 2-hour)+(16.9 MW in RT profiled)
[1A-B]: Includes DR enrolled in the day-ahead load response program; approximately 350 MW, as of early 2008.
[1C-D]: As of June 2008, ISO New England/NEPOOL Demand Resources Working Group Meeting, Demand Resources Department ISO New England, Inc., September 3, 2008
[1E] ISO New England, 2007 Annual Markets Report, June 6, 2008, Table 8-3
[1-2F],[4-7F]: FERC 2007 assessment of Demand Response and Advanced Metering, Figure II-1, Pg 5.
[1-2G],[4-7G]: FERC 2007 assessment of Demand Response and Advanced Metering, Figure II-1, Pg 5.
[2A-B]: As of May, 2008; NYISO, May 2008 Demand Response Registration; Emergency/Reliability = 363.4 MW in EDRP + 1761.1 in SCR
[2E] New York ISO, 2007 State of the Market Report, p.188; 4150 MWh in day-ahead program, 245 MWh in TDRP.
[3A-B]: As of 6/30/2008, PJM, Load Response Activity Report, June 2008
[3C-D]: PJM 2006 State of the Market Report, Table 2-66. Emergency MW is calculated as total MW under DSR Programs Adminstrated by LSEs' in PJM Territory minus price sensitive DSR Distribution.
Economic MW is the sum of price sensitive DSR Distribution and Total MW with full and partial exposure to real time LMP.
[3E] PJM, 2007 State of the Market Report Volume 2: Detailed Analysis, March 11, 2008, p.100 and Table 2-88.
[3F] PJM, 2007 State of the Market Report Volume 2: Detailed Analysis, March 11, 2008, p.98 and p.100.
[3G] Peak load reduction in [3F] divided by 2007 peak load; PJM, 2007 State of the Market Report Volume 2: Detailed Analysis, March 11, 2008, Table 2.2.
[4A]: Megawatt Daily, "Midwest ISO demand response taking shape", October 2, 2008.
[4C-D]: 2007 State of the Market Report, Page xiii
[5C-D]: IRC Harnessing Power of Demand October 2007, Figure 5.
[6B]: As of December 2007, ERCOT 2007 State of the Market Report, p. 78.
[6E]: FERC 2006 assessment of Demand Response and Advanced Metering Footnote, Pg 84.
DR providing ancillary services.

Economic DR is the most prominent in PJM and California, but there is also significant amount of economic DR enrolled in ISO-NE and NYISO.⁵³ Economic DR is estimated to represent only about 5% of the total DR enrolled in LSE-administered programs in the Midwest ISO.⁵⁴

⁵² One of the conditions of DR participation in RPM is that the demand resource must be registered in the full option or capacity-only option of the Emergency Load Response Program.

⁵³ We do not have sufficient data to distinguish between non-RTO emergency and economic programs in and SPP.

⁵⁴ Goldman et al., Coordination of Retail Demand Response with Midwest ISO Wholesale Markets, Ernest Orlando Lawrence Berkeley National Laboratory, Figure 5, LBNL-288E, May 2008.

DR enrollment in non-RTO programs is prevalent in regions where the RTO offers a limited range of DR programs (*e.g.*, CAISO), or no programs at all (*e.g.*, SPP). The Midwest ISO does not yet have any “supply curve” programs,⁵⁵ but has recently instituted its Emergency Demand Response (EDR) Initiative.⁵⁶ RTO “supply curve” programs provide a platform for LSEs and/or CSPs to sell load reductions that are treated like generation and not tied to load bids in the wholesale market. On the other hand, DR that is managed by LSEs and not part of RTO programs reduces an LSE’s actual load and hence its load bid; such DR is “paid” as an offset to load settlement or equivalently, the load pays for its net load. That is, the LSE uses either the “no curves” or “demand curves” approach.

Enrolled MW in DR programs differs from actual *participation*, which is the amount called and the MW and MWh impacts. As Table 6 shows, the enrollment rate versus participation rate varies greatly among RTOs. PJM has the most DR participation in energy markets, with 2,973 MW enrolled in economic programs and 610 GWh of annual deployment. The interpretation of ERCOT’s apparently very high GWh of load reduction is unclear to us, as DR there primarily provides ancillary services.

Annual MWh impacts are primarily due to economic DR, as emergency DR activations are a fairly rare event. For example, PJM activated emergency DR once,⁵⁷ and ISO-NE⁵⁸ and NYISO⁵⁹ each had only two emergency DR activations during 2007. Most DR enrolled in RTO-administered economic programs curtails in real-time following a self-schedule rather than a dispatch instruction (except in NYISO, which only has day-ahead DR participation).

⁵⁵ It will when the ASM market starts on January 6, 2009.

⁵⁶ As Table 6 shows, the Midwest ISO has partially accommodated DR in its markets without having special “programs,” but CSPs have not been able to participate, and DR is not able to set the price in real-time.

⁵⁷ PJM, 2007 State of the Market Report, p.97.

⁵⁸ ISO-NE, 2007 Annual Markets Report, p.142.

⁵⁹ NYISO, Reports on Demand Side Programs, New Generation, and the ICAP Demand Curves under ER01-3001, et al, filed with the FERC on January 15, 2008, p.11.

Based on the number of MWs of enrolled DR and the amount of DR deployed during the system peak, the amount of DR in the Midwest ISO is similar to that in other RTOs (even though the higher reserve margins would suggest a smaller economic potential).

VI.C THE ABSENCE OF CSPs IN THE MIDWEST ISO FOOTPRINT

Most RTOs do not report the amount of DR provided through CSPs versus LSEs. An exception is the NYISO, which recently reported that CSPs form the majority of participants in its reliability programs, and non-transmission owner LSEs (*i.e.* CSPs, competitive LSEs, and direct wholesale customers) provide almost two-thirds of all reliability DR.⁶⁰ In addition, comments from FERC and the RTOs, publicly available data on CSPs, and our interviews with the three largest CSPs indicate that CSPs contribute a large fraction, if not the majority, of DR in PJM and ISO-NE, as well.⁶¹

VI.C.1 Comments by FERC and RTOs

The FERC 2007 Assessment of Demand Response and Advanced Metering (pp. 20-21) discusses the value the CSPs provide:

Increased Activity by Third Parties in Aggregating and Providing Demand Response Third-party providers who generally aggregate demand reductions across customer groups and bid a percent of their enrolled base into the market provide an important avenue for customers to contribute to demand reduction that they might not otherwise have. Third-party providers provide a mechanism for customers to bid into energy markets without having to understand and track energy markets or multiple RTO/ISO or state rules. PJM's Andy Ott stated:

"They're actually providing a very valuable service, because each individual entity who can provide demand response, can't afford to take the time to understand the market in depth, the wholesale market, so you have curtailment service providers actually providing a function to provide commonality, to allow those megawatts to come to the market. That's absolutely valuable, and we see their actions every day."

⁶⁰ NYISO, Reports on Demand Side Programs, New Generation, and the ICAP Demand Curves under ER01-3001, et al, filed with the FERC on January 15, 2008.

⁶¹ This could, in fact, be due to the retail choice environments prevalent in the East, whereas, MISO has mostly a regulated rate environment.

Demand-response aggregators delivered significant levels of demand reductions during the summer of 2006, including 3000 MW in the Midwest ISO. RTOs and ISOs estimate that aggregators' contribution to load reductions comprise a sizable portion of the enrolled customers in their reliability-based programs. For example, in NYISO's ICAP/Special Case Resources program, aggregators provided 91 percent of participating customers, and 53 percent of demand reductions in 2006.

TVA similarly notes that third party aggregators are a big part of their business case in rolling out its pilot program for commercial and industrial customers, because the aggregators have the manpower, time, and money to run a program.

Third-party aggregators have also been active in signing long-term demand contracts with utilities. The California PUC issued an order directing utilities to cooperate with aggregators, and to pursue requests for proposals for additional demand response. EnerNOC won two "Negawatt Network" contracts for 40 MW each with Pacific Gas & Electric (PG&E) and with Southern California Edison (SCE) that were approved by the CPUC. EnerNOC also entered into a ten year Negawatt Network contract with Public Service of New Mexico (amount not announced) in support of New Mexico's Efficient Use of Energy Act. Comverge will provide San Diego Gas & Electric (SDG&E) and PG&E with up to 100 and 50 megawatts of capacity, respectively, for their residential and small commercial and industrial customers. The CPUC also approved a five-year agreement between PG&E and Energy Curtailment Specialists, Inc., for a minimum of 40 MW from commercial and industrial customers.

"Third party demand aggregators bring value to smaller retail customers by providing the opportunity to participate in wholesale markets as demand response, where they otherwise may be precluded from participating, whether by rule or practical effect. This, in turn, increases the potential market and reliability benefits realized from demand response in wholesale markets." COMMENTS OF PJM INTERCONNECTION, L.L.C. pursuant to the Commission's Advanced Notice of Proposed Rulemaking

VI.C.2 Available Data on Enrollment of CSPs

The available data on CSPs from our sources indicate the following:

- In NYISO, CSPs account for 91 percent of participation in ICAP/SCR capacity program and 53 percent of all DR reductions.⁶²
- Energy Curtailment Specialists (ECS) provides 786 MW, or 70 percent of DR participating in the ICAP/SCR program providing capacity in the NYISO capacity market.⁶³

⁶² FERC 2007 Assessment of Demand Response and Advanced Metering, page 20.

- EnerNOC provides 623 MW DR in CT (8.3 percent state peak) and 170 MW DR in ME (8.4 percent state peak).⁶⁴
- Comverge provides 1500 MW DR total, but approximately 700 MW of that is from fee-for-service contracts with utilities. Approximately 800-900 MW follows the CSP “supply curves” model, mostly in PJM programs. Comverge acquired these resources through its acquisition of Enerwise.⁶⁵

CSPs can provide expertise, technology, and a willingness to take risk that many utilities lack. LSEs and CSPs are not necessarily in competition with each other. For example, CSPs may be able to approach more customers that LSEs find difficult to manage. Furthermore, working through LSEs may reduce the CSPs’ marketing costs.

On October 17, 2008 FERC approved a new rule that obligates RTOs to accommodate CSPs in organized markets, unless state regulations do not permit this. The FERC rule sets forth criteria that allow each RTO to implement these provisions according to their own specific circumstances, including (1) an equal treatment of CSP DR bids and DR bids by other entities; (2) RTOs can set their own registration, credit and certification requirements; (3) RTOs may require that aggregated bids be from a single, reasonably-defined area. All RTOs have compliance filings related to this ruling due on April 28, 2009.

⁶³ *Brattle* interview with Paul J. Tyno, Executive Vice President Program Development, Energy Curtailment Specialists, Inc., February 19, 2008.

⁶⁴ Demand Side Management: Firm Resource 2007 Electric Market Forecasting Conference Skamania, WA September 13, 2007.

⁶⁵ *Brattle* interview with Cynthia Arcate, Business Development Director - NY/NE, Comverge, Inc., February 15, 2008.

VII. ECONOMIC DR POTENTIAL IN THE MIDWEST ISO

Today in the Midwest ISO, nearly all DR comes from “reliability-based” DR programs such as direct load control (DLC), and interruptible service.⁶⁶ However, the region has the potential to achieve significantly higher levels of DR. Much of this could come through price-based DR programs such as dynamic pricing, and several factors suggest that the potential impacts of this untapped resource could far exceed those of today’s DR programs. How large is this potential, and how much of that potential is the Midwest likely to reach under today’s policies? This section answers those questions by quantifying DR potential in the Midwest ISO service territory.

Two types of DR potential are quantified. The first, maximum achievable potential (MAP), represents the high end of achievable impacts, accounting for market acceptance rates of all cost-effective DR programs. The second type, realistic achievable potential (RAP), reflects the degree of willingness of regulators and utilities to pursue the MAP. Thus, the RAP projection is a subset of the MAP projection. The integration of DR into the Midwest ISO’s electricity markets is a significant opportunity to bridge the gap between today’s most likely projection of DR impacts (RAP) and a higher projection that is both feasible and cost-effective (MAP). As a first step, it is necessary to better understand today’s DR resource base in the Midwest ISO.

According to the North American Electric Reliability Corporation (NERC), the Midwest ISO has one of the largest existing DR resource bases in the country. NERC’s assessment indicates that current enrollment in DR programs in the Midwest Reliability Organization (MRO) could produce a six percent reduction in the system peak.⁶⁷ The only NERC region with a larger resource is Florida. A summary of existing DR resources by region is shown in Figure 7.⁶⁸

⁶⁶ As noted above, there is also a significant amount of behind-the-meter generation.

⁶⁷ MRO is the NERC region that most closely represents Midwest ISO’s service area geographically, although Midwest ISO also extends to parts of RFC and SERC with significant load in those areas.

⁶⁸ It should be noted that a recent survey of utility DR programs in the Midwest has suggested that the actual available DR resource could be significantly less than NERC’s estimate. The LBNL survey found that the available DR resource was less than half of the NERC estimate. See Ranjit Bharvirkar, Chuck Goldman, and Grayson Heffner, “Retail Demand Response Program Survey: Preliminary Results,” November 2007.

FIGURE 7: NERC FORECAST OF DR FOR 2008 SUMMER PEAK^{69,70}

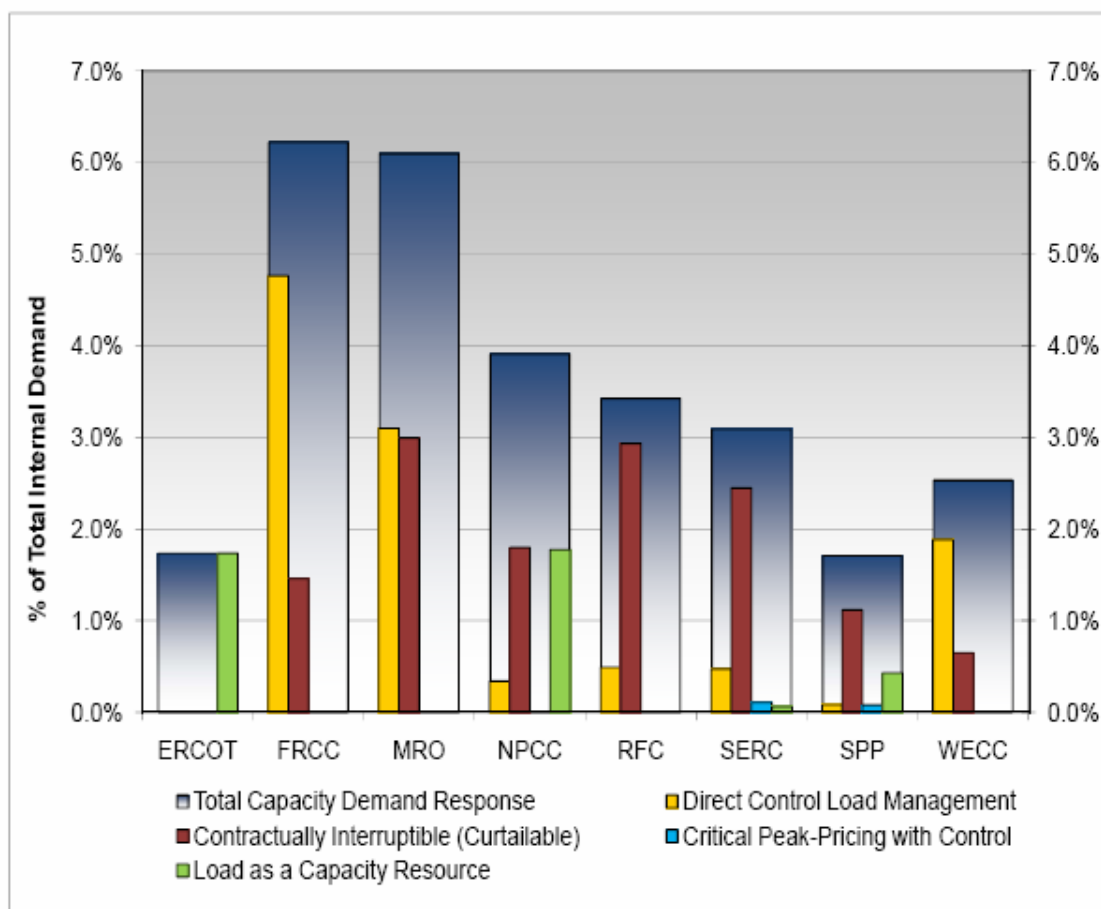


Figure 7 identifies two sources of DR in the Midwest: direct control load management (direct load control, or “DLC”) and contractually interruptible demand (or “interruptible service”). As discussed earlier in Section II, in a DLC program, customer end-uses are directly controlled by the utility and are shut down or reduced to a lower consumption level during emergency conditions. In an interruptible service program, customers agree to reduce consumption to a pre-specified level, sometimes called the firm service level, or by a pre-specified amount, during emergency conditions. In return, customers receive a payment for participating. The payment could take the form of a rebate for every kilowatt-hour that is reduced when needed, a monthly

⁶⁹ Source: NERC, “2008 Summer Reliability Assessment,” May 2008, p. 13.

⁷⁰ NERC’s definition of total internal demand for a region is the projected metered internal generation and line flows into the region, less metered line flows out of the region. This includes the projected impacts of DSM programs but not DR programs. This definition is consistent with system peak demand used elsewhere in this section. For a complete definition see: http://web.njit.edu/~ses5/NERC_Demand_Capacity_Form_Instructions.pdf

capacity reservation payment simply for being enrolled, or both. It often includes simply a rate reduction.

Both DLC and interruptible service represent what is sometimes referred to as reliability-based DR or load control. These are traditional forms of DR that have been utilized by utilities for decades, primarily as a last resort resource for addressing unexpected emergency situations on the grid, such as a unit outage or an unanticipated heat wave. These programs are not usually triggered solely by market conditions, such as high day-ahead electricity prices. However, they could be used in those situations as well. Pricing programs, as discussed above, are a newer form of DR, sometimes referred to as price-based DR, falls into this second category.

Dynamic rates require that customers be equipped with meters that can measure consumption in small time intervals of one hour or less, as well as a communication system to let customers know when prices change. In the Midwest ISO, many large commercial and industrial (C&I) customers are already equipped with interval meters. Most residential and small C&I customers are not. However, this is beginning to change with the deployment of advanced metering infrastructure (AMI) in several utility service areas. Among its many benefits, AMI equips customers with the meters necessary to provide dynamic rates.

While the penetration of AMI in the Midwest remains low, several large Midwestern utilities have announced full deployment plans for the near future. These utilities account for roughly a quarter of annual sales in the Midwest ISO. A summary is provided in Table 7.⁷¹

⁷¹ Sources of AMI deployment plans are various recent utility press releases. The descriptions reflect the utility characterizations of their programs.

TABLE 7: ADVANCED METERING DEPLOYMENT PLANS AT MIDWESTERN ELECTRIC UTILITIES

IOU	Deployment Plan Status
Wisconsin Public Service Corp.	Installed
Lake Country Power	Installed
Indianapolis Power and Light*	Installed
Duquesne Light*	Installed
Northeastern REMC	In Deployment
Ameren**	In Deployment
Wisconsin Electric Power Co.*	Contracted
Northern States Power (Xcel Energy)	Contracted
South Central Indiana Rural Electric	Contracted
Detroit Edison Co.	Utility Plans

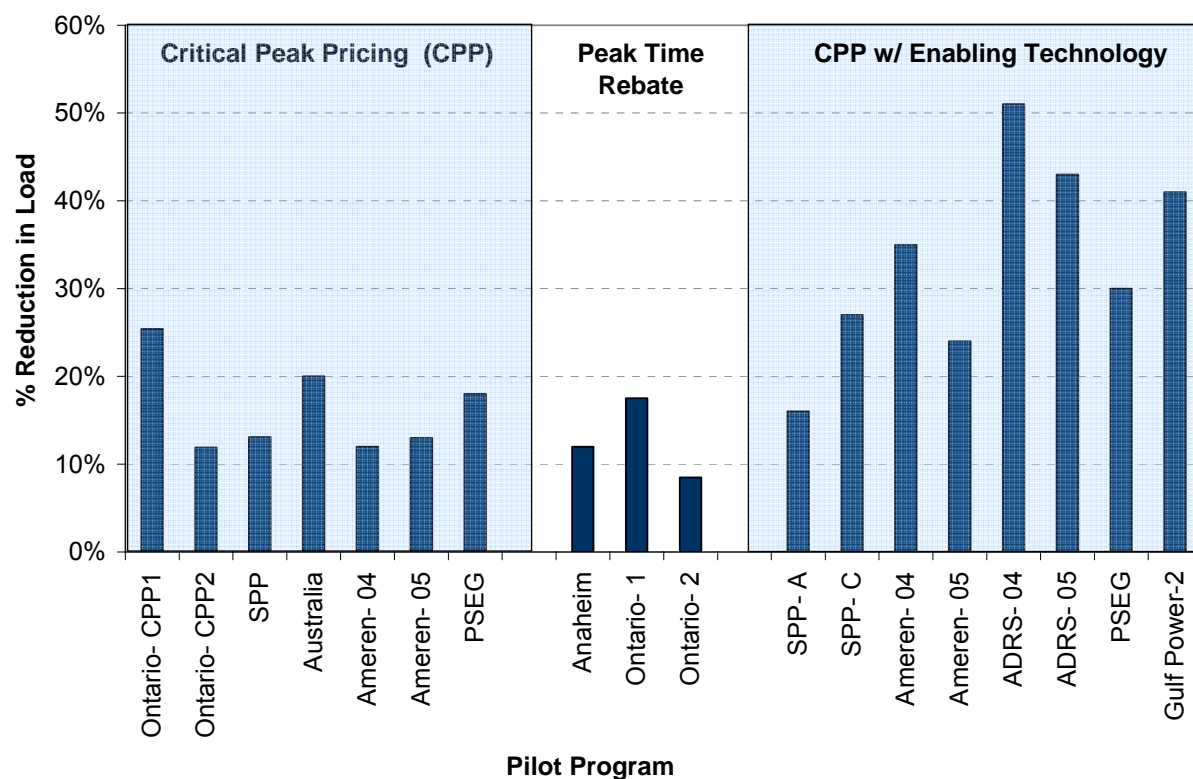
* Indicates deployment of advanced meter reading (AMR), which can potentially enable offering of dynamic rates with a technology upgrade.

** Indicates partial AMI deployment for 1.1 million Illinois electric and gas customers.

Dynamic pricing has been shown to generate significant levels of DR, particularly for the residential class as compared with C&I. A survey of recent dynamic pricing pilots shows that, depending on the type of rate that is being offered and whether customers are equipped with technologies that facilitate demand reductions, peak savings can range between 10 to 50 percent of peak demand. These results are summarized in Figure 8.⁷²

⁷² Ahmad Faruqui and Sanem Sergici, "The Power of Experimentation," posted at the Social Science Research Network, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1134132, August 2008.

FIGURE 8: PEAK IMPACTS FROM RECENT RESIDENTIAL DYNAMIC PRICING PILOTS ⁷³



At most utilities in the Midwest ISO region, there is little dynamic pricing. Residential and small C&I customers receive electric service almost entirely on flat and fixed tariffs, and there has been very little switching away from incumbent providers (utilities) to competitive retailers in those states that allow retail access. Medium C&I customers are generally either on fixed tariffs or on TOU rates, but they are also exposed to a charge based on the size of their maximum billing demand. TOU rates do not include the capability to send varying day-ahead price signals, which can dramatically increase the level of DR achieved by the rate. However, large commercial and industrial customers in restructured markets are exposed directly to wholesale market prices, and to this extent could be considered to be on a “dynamic rate.”

⁷³ For a detailed description of each pilot presented in this chart, see Ahmad Faruqui and Sanem Sergici, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1134132, November 13, 2008.

VII.A THE MIDWEST ISO'S MAXIMUM ACHIEVABLE DR POTENTIAL

Despite the current lack of price-based DR in the Midwest ISO, there are a number of reasons to believe that it could play a much larger role in the Midwest over the next 20 years. First, AMI investment costs are rapidly falling. In some cases, AMI investments can be justified purely by the operational savings that they provide (*i.e.* eliminated meter reading costs, faster outage detection, remote connect and disconnect, and so on) and in other cases are shown to be justified by the additional avoided costs that will be achieved through dynamic pricing.⁷⁴ As was illustrated in Table 7, there has already been some investment in AMI in the Midwest, and this is likely to increase in the future. Additionally, the success of dynamic pricing pilots around the country suggests that dynamic pricing will be a significant source of peak reductions.

The second driver of the national trend toward price-based DR is the falling cost of behind-the-meter “enabling technologies.” Enabling technologies help customers reduce their consumption during peak periods. One example is the programmable communicating thermostat (PCT). The PCT allows the utility or system operator to adjust the set-point on the customer’s thermostat during high-priced periods. Either the operator can control the operation or it can respond to a pre-set price signal. The retail price of these devices has fallen from \$300 to less than \$100 in less than three years, and the devices are now available at retail outlets such as Home Depot. Another example is the in-home display (IHD). IHDs provide consumers with detailed real-time information regarding their electricity consumption pattern and cost. Equipped with this information, customers have a better understanding of how to change their consumption behavior to maximize bill savings under dynamic tariffs. In a recent study, customers equipped with the device were able to reduce their energy consumption by 6.5 percent compared to a statistically balanced control group that did not have the device.⁷⁵

A third factor suggesting that price-based DR will play a larger role in the future is policy action that has recently taken place at both the state and federal levels. For example, at the state level,

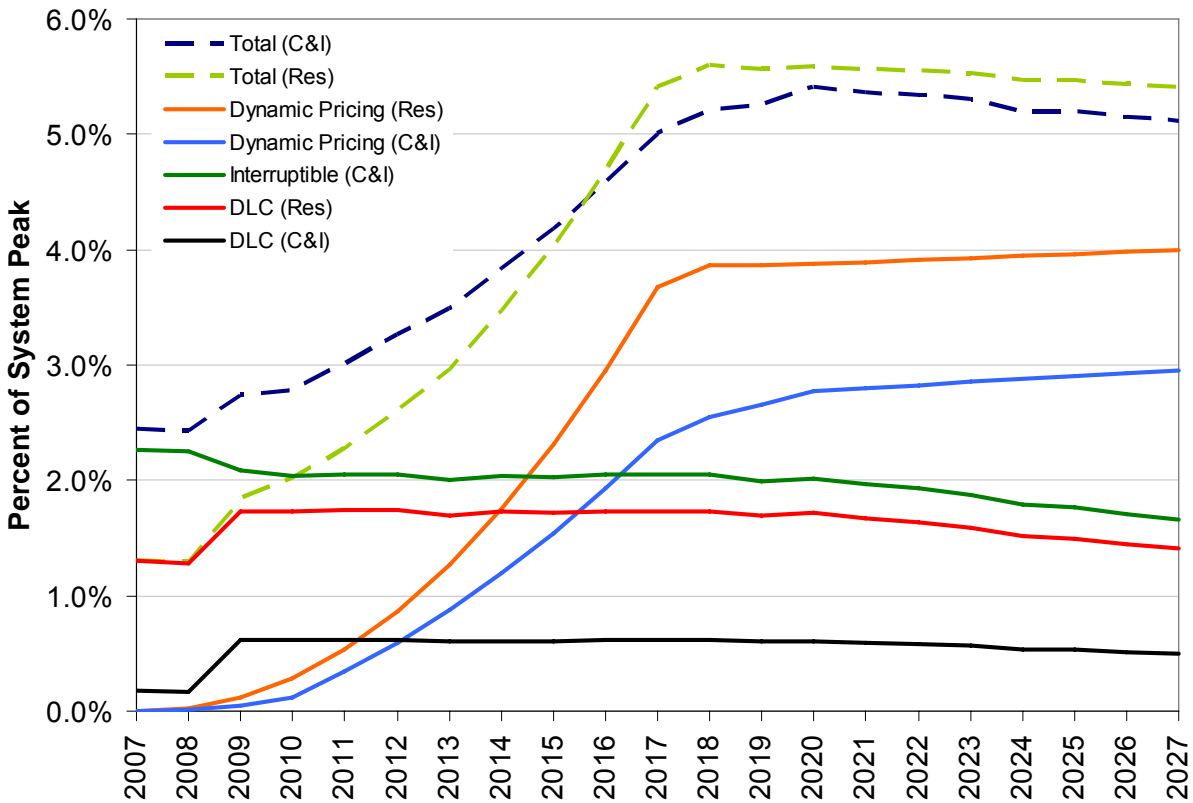
⁷⁴ Based on an interview with staff at Idaho Power, which recently filed for approval of a full-scale AMI investment.

⁷⁵ Hydro One, “The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot,” March 2006.

California has established a goal of five percent peak reduction from price-based DR, and recently the California Public Utilities Commission (CPUC) issued a decision that would make dynamic pricing the default tariff for all but the residential class of customers. At the federal level, as part of a congressional mandate, the Federal Energy Regulatory Commission (FERC) is currently pursuing a detailed, bottom-up assessment of state-level DR potential, including price-based DR. Actions such as these suggest that future policies could play a large role in promoting price-based DR.

The projection of Midwest ISO's MAP reflects the belief that this trend toward price-based DR will continue. In the early years of the forecast, DLC and interruptible service will continue to serve as the primary source of DR in Midwest ISO. However, by around 2015, as AMI deployments ramp up and awareness of dynamic pricing at the customer, utility, and regulatory levels increases, dynamic pricing has the potential to exceed the impacts of these traditional, reliability-based programs. In the later years of the forecast it is anticipated that some of the customers enrolled in these reliability-based programs will switch over to the price-based programs due to the opportunity for greater bill savings. Figure 9 summarizes the MAP DR coincident peak impact projection for the Midwest ISO. For a description of the methodology behind these projections, see Appendix B.

FIGURE 9: MAP PROJECTION BY SOURCE OF DR ⁷⁶



VII.B MIDWEST ISO'S REALISTIC ACHIEVABLE DR POTENTIAL

The DR projections presented previously represent an aggressive estimate of the amount of DR that could feasibly and cost-effectively be achieved in the Midwest ISO. However, these projections do not necessarily reflect some of the regulatory and political barriers that could prevent DR from reaching its full potential. Based on recent historical trends in demand-side efforts in the Midwest, a RAP projection was developed to reflect the impacts of these additional barriers. The RAP projection should be considered a likely scenario based on the current situation in the Midwest.

By its nature, the RAP projection is more subjective than the MAP projection. It is influenced by a number of driving factors, all of which are intended to reflect the willingness of utilities and regulators to pursue demand-side resources in the Midwest. The drivers include:

⁷⁶ Totals may not add to NERC estimate due to use of different data sources. Impacts are coincident with Midwest ISO peak demand.

- State-level regulatory incentives;
- Per-capita expenditures on energy efficiency, as an indicator of willingness to invest in DR; and
- DSM goals.

These drivers are generally not specific to DR, but instead are representative of an overall receptiveness of regulators and utilities to demand-side efforts (including energy efficiency). Regardless, they can serve as indicators for approximating the level of DR that might be pursued in the region.

VII.B.1 State-Level Regulatory Incentives

Without certain regulatory mechanisms in place, utilities generally have a disincentive to pursue programs that will reduce revenues, such as energy efficiency and DR.⁷⁷ Ultimately, the reduction in sales that results from these programs will cause the utility to fall short of recovering the fixed revenue requirement that would otherwise be recovered in the absence of the sales reduction. To address this, some states have regulatory measures in place to either remove this disincentive, or provide a financial incentive to pursue demand-side programs.⁷⁸ The regulatory mechanisms fall into three categories:

- *Direct cost recovery:* This is the most common form of regulatory incentive. It allows utilities to recover the DSM program implementation costs in a timely manner. It is also the weakest of the three mechanisms for promoting DSM.
- *Fixed cost recovery:* This category includes “decoupling.” Essentially, the link between sales and revenue is removed and utilities are allowed to true-up their rates between rate cases to recover the lost revenues associated with the decreased electricity sales.

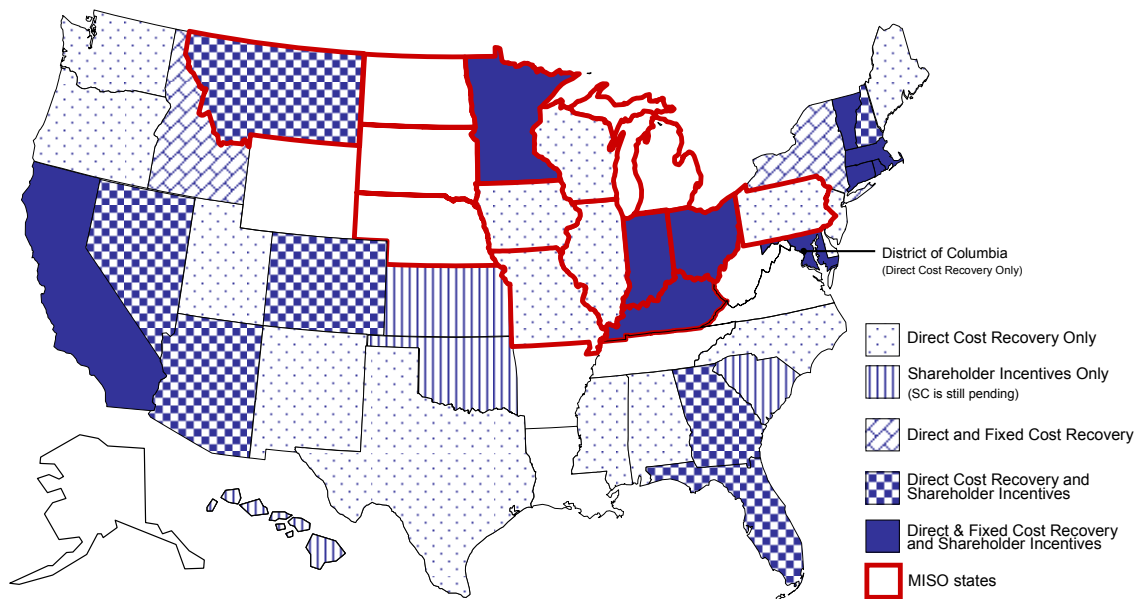
⁷⁷ While energy efficiency decreases overall sales and therefore revenues, DR will not have a big impact on overall kWh sales. Instead, any revenues from charges that are dependent on peak usage, such as a demand charge, will be reduced by DR.

⁷⁸ Currently, fixed cost recovery mechanisms and shareholder incentives typically only apply to energy efficiency measures.

- *Shareholder incentives:* This includes all models that are designed to provide utilities with a financial incentive above and beyond their normal rate of return on investments. A recent example is California's Shared Savings model, which shares the net benefits of DSM impacts between the utility and the consumer. The Duke Save-a-Watt model is another such example.

As can be seen from Figure 10, there is a range of regulatory mechanisms in place in the various Midwest ISO states. Most states have either no cost recovery mechanisms (ND, SD, NE, and MI) or only a direct cost recovery mechanism (IA, MO, IL, WI, and PA). However, four states have all three mechanisms in place (MN, IN, OH, and KY) and Montana has both shareholder incentives and direct cost recovery. Overall, this mix is generally consistent with the country as a whole and does not necessarily suggest that the Midwest is ahead of or behind the curve on this driver.

**FIGURE 10: REGULATORY MECHANISMS FOR PROMOTING DSM
AT ELECTRIC UTILITIES**



Source: National Action Plan for Energy Efficiency Leadership Group, "Aligning Utility Incentives with Investment in Energy Efficiency," November 2007. Includes additional information to reflect recent regulatory changes. Note that Direct Cost Recovery mechanisms include: rate case, system benefits charges, and tariff rider/surcharges; Fixed Cost Recovery mechanisms include: decoupling and lost revenue adjustment mechanisms. Shareholder Incentives include performance incentives.

VII.B.2 Energy Efficiency Expenditures

Another potential indicator of the likelihood of regulators and utilities to adopt price responsive demand could be the willingness to spend money on demand side efforts such as energy efficiency. Due to the interrelated nature of energy efficiency and DR programs, significant expenditures on DSM would suggest that, at the utility level, the funding mechanisms are in place to develop budgets for demand side programs, which could ultimately include DR. Regulatory approval of these expenditures would further signal that regulators in the state see value in cost-effective demand-side resources and are willing to pursue them. The American Council for an Energy-Efficient Economy (ACEEE) has compiled the per-capita DSM expenditures for each state in the country in 2006. This is summarized for the Midwest ISO states in Table 8.

TABLE 8: PER-CAPITA ENERGY EFFICIENCY EXPENDITURES IN 2006

MISO State	Per Capita Spending	Rank
Minnesota	\$10.95	8
Iowa	\$9.76	12
Wisconsin	\$9.76	12
Montana	\$8.63	14
Nebraska	\$2.49	24
Ohio	\$1.41	26
Kentucky	\$1.00	29
Michigan	\$0.79	30
North Dakota	\$0.73	31
South Dakota	\$0.70	32
Indiana	\$0.33	36
Pennsylvania	\$0.28	37
Illinois	\$0.24	38
Missouri	\$0.16	46
U.S. Median	\$1.64	-

Source: ACEEE, "The State Energy Efficiency Scorecard for 2006", June 2007

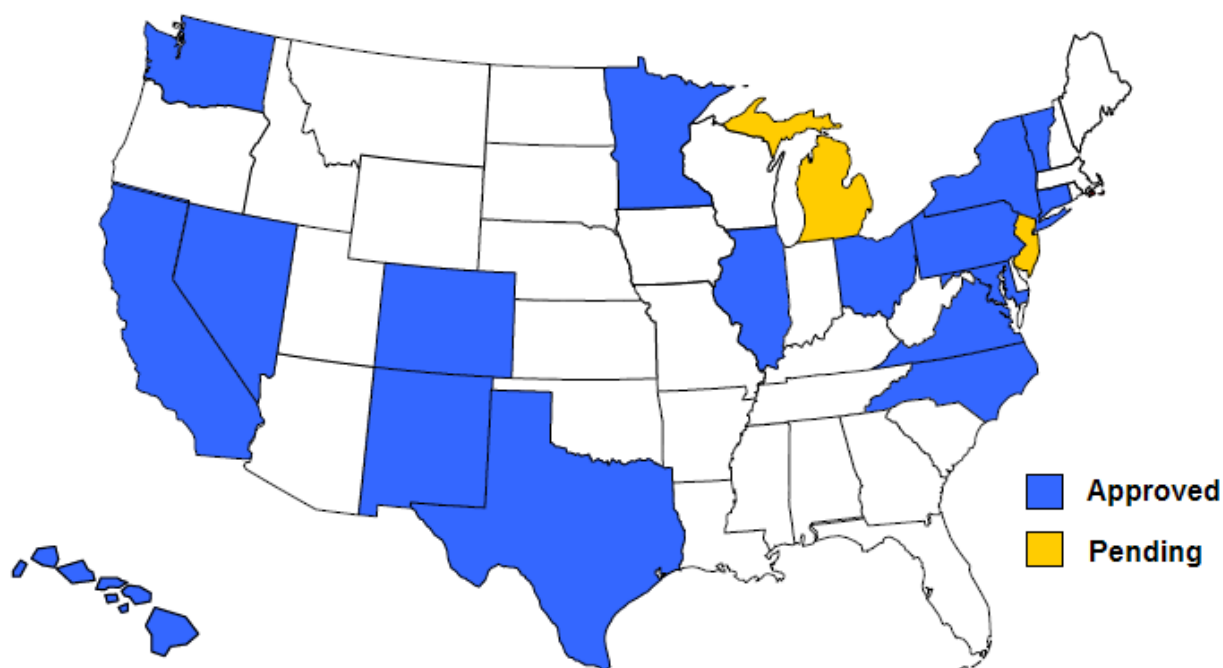
Five Midwest ISO states are above the US median for per capita expenditures, representing only 25 percent of electricity sales in all Midwest ISO states. The remaining nine states are below the

national median, very significantly in some cases. The general implication of this metric is that the region lags somewhat behind the nation as a whole on DSM spending.

VII.B.3 DSM Goals

State DSM goals can also be used to gauge how much importance is given to demand side resources. While these goals should not necessarily serve as an estimate for the level of DSM that will actually be achieved in the state, they do at least represent a level of attention that is being paid to demand side resources by regulators. Figure 11 provides a summary of DSM goals for each state in the U.S.

FIGURE 11: STATE-LEVEL DSM GOALS (AS OF MAY 2008) ⁷⁹



Across the country, “aggressive” DSM goals generally aim to achieve roughly a 20 percent reduction in electricity sales by 2020. In the Midwest ISO, three states (OH, IL, MN) meet this criterion. A fourth state (MI) has a pending DSM goal with a similar objective but a shorter timeframe, aiming to reach one percent annual savings by 2012. Pennsylvania also has a DSM-

⁷⁹ Source: ACEEE, “State Energy Efficiency Resource Standard (EERS) Activity,” May 2008.

related goal, although it is not as aggressive as these other targets. It identifies energy efficiency as one of many resources that should be used to meet growing demand for electricity but does not include a specific target for energy efficiency savings. The remaining nine MISO states do not have widely publicized DSM goals. Generally, the Midwest region as a whole, along with the Southeast, tends to lag behind the established DSM goals in other regions of the country.⁸⁰

Based on these three subjective drivers, the MAP projections are reduced to reflect the likely will of utilities and regulators to pursue DR in the Midwest. The DLC and interruptible service projections in the MAP forecast do not rise significantly above today's levels, so there is no strong reason to believe that they cannot remain at that level for the forecast horizon. However, there is significant uncertainty in the dynamic pricing projections. Given this uncertainty and the significance of the drivers described above, it is likely that the dynamic pricing RAP impacts will not reach the MAP projections.

To adjust the dynamic pricing impacts to develop a RAP projection, the results of a recent Delphi Poll were used as the starting point.⁸¹ In this poll, 50 industry experts around the United States indicated that roughly half of a national MAP forecast for DSM would actually be achieved. In other words, the experts estimated that the national average RAP is about 50 percent of MAP. For the purposes of this analysis, the Midwest ISO MAP could simply be cut in half to represent this relationship. However, that would not account for the region-specific differences indicated by the previously discussed drivers.

An analysis of the drivers suggests that the Midwest is currently slightly lagging behind the nation as a whole in terms of the region's political willingness to pursue demand-side resources. While the region's regulatory mechanisms for promoting DSM are roughly on par with the rest of the country, it lags slightly behind in its per-capita spending on energy efficiency and in its state-level DSM goals.

⁸⁰ To the degree that end-use rates in the Midwest ISO footprint are lower than in the rest of the country, of course, the propensity for DR is naturally lower.

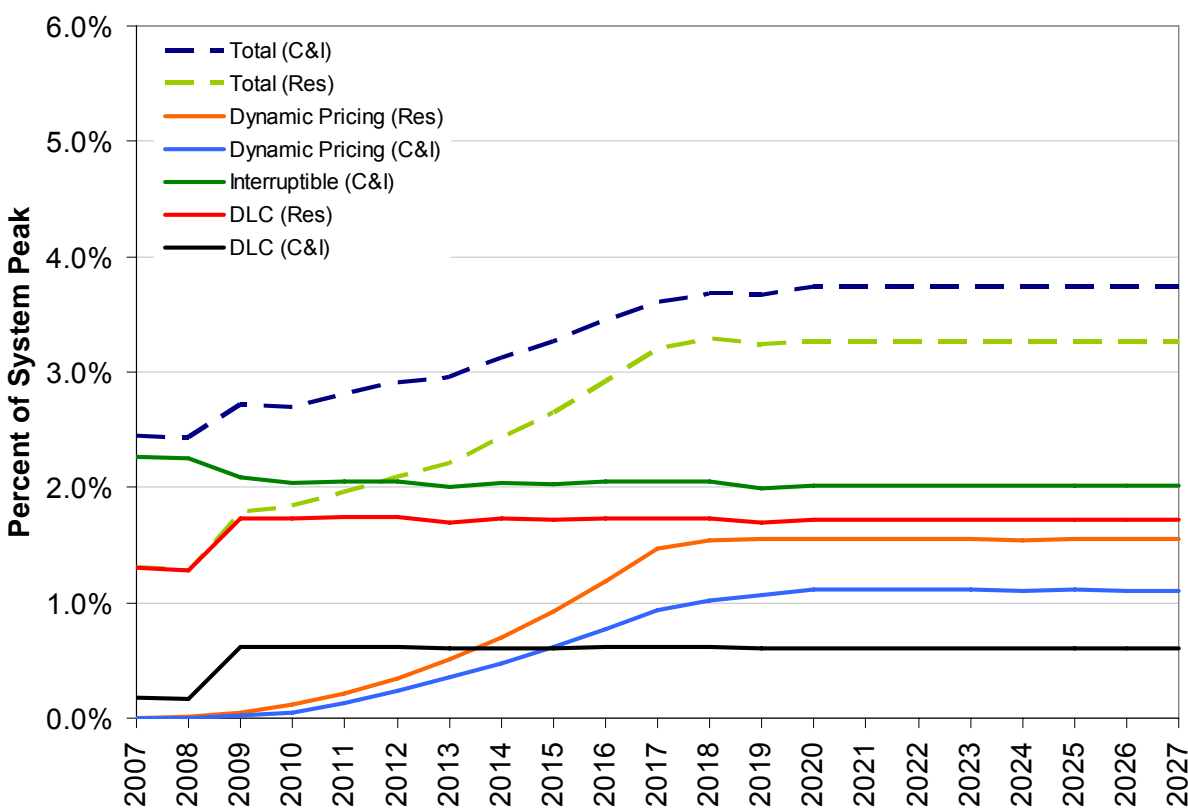
⁸¹ EPRI/EEI, "Assessment of Achievable Potential of Energy Efficiency and Demand Response in the U.S. (2010-2030)," conducted by Global Energy Partners, LLC and *The Brattle Group*. Results forthcoming.

One explanation for this could be that electricity prices in the Midwest are lower than the national average as a result of the large share of cheap coal-fired generation in the region. For example, in 2006 the average retail electricity price in the Midwest ISO was 7.2 cents/kWh, while the national average was 8.9 cents/kWh.⁸² This low electricity price would limit the number of cost-effective DSM measures that could be pursued in the region.

Ultimately, to quantify the relevance of these drivers and to convert the MAP forecast to the RAP forecast, the MAP dynamic pricing impacts were reduced by 60 percent. This represents an environment at the regulatory and utility levels in the Midwest that historically has proven to be slightly less receptive to demand-side efforts than other parts of the country. It is also assumed that there will not be switching from reliability-based programs to price-based programs under this scenario. The results of the RAP forecast are illustrated in Figure 12. In this forecast, the dynamic pricing impacts are expected to be slightly lower than the DLC and interruptible service impacts by the later years of the forecast.

⁸² Sales-weighted averages calculated using data from the EIA-861 database.

FIGURE 12: MIDWEST ISO RAP PROJECTION BY SOURCE OF DR⁸³



The RAP analysis can also be useful for identifying the regions within the Midwest ISO that are more or less likely to provide DR. To do this, each of the drivers of the RAP forecast is considered on a state-by-state basis. Depending on the strength of each driver in each state, a rating of “high,” “moderate,” or “low” is subjectively assigned. The composite of these ratings across the drivers results in a final rating for each state. The rating could be interpreted as an estimation of the state’s likelihood of providing DR reductions beyond its RAP.

For example, as was illustrated in Table 8, Minnesota is the eighth ranked state in the U.S. in terms of energy efficiency expenditures. As a result, Minnesota would receive a “high” rating for this driver. Alternatively, Missouri, which is ranked 46th out of 50 states, would receive a “low” rating. General rules of thumb for assigning the ratings for each DR driver are described in Table 9.

⁸³ Impacts are coincident with Midwest ISO peak demand.

TABLE 9: DR DRIVER RATING CRITERIA

	Rating		
	High	Moderate	Low
AMI Deployment	Significant number of meters deployed or contracted	Some meters deployed or planned	Little meter deployment
Regulatory Incentive	Shareholder incentives <u>and</u> cost recovery (fixed or direct)	Shareholder incentives <u>or</u> cost recovery (fixed or direct)	<u>No</u> shareholder incentives or cost recovery
DSM Expenditures	Top 15 rank in U.S.	Ranked 16 to 35 in U.S.	Bottom 15 rank in U.S.
DSM Goals	Existing aggressive goal	Pending aggressive goal	Weak or no goal

Using these criteria, each state in the Midwest ISO can be rated across the DR drivers. The resulting ratings are shown in Table 10.

TABLE 10: STATE RATINGS ACROSS DR DRIVERS

	AMI Deployment*	Regulatory Incentive	DSM Expenditures	DSM Goals	Total Rating
Minnesota	High	High	High	High	High
Ohio	Low	High	Moderate	High	Moderate
Illinois	High	Low	Low	High	Moderate
Kentucky	Low	High	Moderate	Low	Moderate
Michigan	Moderate	Low	Moderate	Moderate	Moderate
Indiana	Moderate	High	Low	Low	Moderate
Wisconsin	High	Low	High	Low	Moderate
Montana	Low	High	High	Low	Moderate
Iowa	Low	Low	High	Low	Low
Missouri	Low	Low	Low	Low	Low
Pennsylvania	Moderate	Low	Low	Moderate	Low
Nebraska	Low	Low	Moderate	Low	Low
North Dakota	Low	Low	Moderate	Low	Low
South Dakota	Low	Low	Moderate	Low	Low

**Only includes AMI deployment in MISO service territory*

The states with the highest likelihood of producing significant DR impacts tend to cluster in the area surrounding the Great Lakes. Minnesota ranks the highest, with a “high” rating across all of the DR drivers. Ohio, Illinois, Kentucky, Michigan, Indiana, Wisconsin, and Montana have a

mix of ratings that lead to an overall “moderate” rating for DR potential. The remaining states in the Midwest ISO have a lower likelihood of producing a significant amount of DR.

VII.C CONCLUSIONS

There appears to be an opportunity to significantly increase the amount of DR that is currently available in the Midwest ISO footprint. An estimate of feasible and cost-effective DR potential for the region suggests that the current resource base could be nearly doubled through aggressive DR policies over the next 20 years.⁸⁴ This potential growth in the size of the DR resource would likely come from price-based DR options such as dynamic pricing. As the costs of technologies that support these new rate forms continue to fall, and as regulators and utilities continue to pay increasing attention to their potential, they could play a significantly larger role in future DR efforts than today’s reliability-based programs which have remained largely unchanged for decades.

The potential benefits of this increase in the size of the DR resource base are many. For the Midwest ISO, additional DR could increase competitiveness in its wholesale markets and help support system reliability. It also would provide financial benefits to the region’s utilities and end-use customers in the form of avoided generating capacity, energy, and transmission and distribution costs. Ultimately, some or all of these financial benefits would be passed through to consumers in the form of bill savings.

However, most recent trends in the Midwest have not indicated that there is currently momentum toward capitalizing on this opportunity and pursuing the price-based DR resource. While some utilities have announced AMI plans, none have recently conducted experimental pilots to test the potential benefits of dynamic pricing on their systems. Further, regulators in some states have shown interest in demand-side resource potential, but the region as a whole is slightly lagging behind much of the rest of the nation in this regard. A forecast of the realistic potential for DR in the region suggests that price-based DR may only rise to nearly the level of today’s existing reliability-based DR resources.

⁸⁴ NERC estimates that the size of the existing resource in the Midwest is six percent, and the MAP estimate developed in this report is approximately 11 percent by 2027.

VIII. RECOMMENDATIONS AND NEXT STEPS FOR MIDWEST ISO

As discussed above, the ability of the Midwest ISO to increase participation of DR in its energy markets depends on a variety of factors, not all of which are under its control. To the degree that state jurisdictions act to further encourage DR and enable LSEs or CSPs to further develop end-use DR programs that can participate in the Midwest ISO energy markets either through dynamic pricing or the supply curves approach, the Midwest ISO should be working to ensure that its business rules reasonably accommodate the DR programs that the states enable (the key business rules are discussed in Section V). However, it is important to note that the Midwest ISO already accommodates the “demand curves” approach to DR in its day-ahead energy market. The WPS program discussed above is an example of that.

In developing a roadmap to enabling the dominant and most promising forms of economic DR, the Midwest ISO must recognize the likelihood of dynamic pricing programs becoming widespread in its footprint in the next five to ten years. However, it is also likely that fixed rates will remain the dominant retail rate structures in the next two to five years, in which case only direct or indirect load control can be used to create economic DR. Load control can be facilitated by either LSEs or CSPs. A primary choice facing the Midwest ISO is whether to keep with its current philosophy of using the “demand curves” approach (with extension to real time and whatever modifications may be necessary to better accommodate existing and likely future DR end-use programs), or whether it should also fully enable the “supply curves” approach with the likely entry of CSPs.

The challenge of the “demand curves” approach is that it appears that participation through that approach is limited. In contrast, the supply curves approach brings with it baseline definition and M&V issues, questions about the level of compensation to DR providers, and increased costs for the RTO and market participants. Subject to some caveats, our recommendation is for the Midwest ISO to consider changing its tariff and business practices to accommodate the “supply curves” approach that would facilitate the entry of CSPs. To their merits, CSPs play an important role in PJM, NYISO, and ISO-NE. CSPs have brought large amounts of DR into the market through their marketing, innovation, and specialized technical expertise, and the subsidization that has occurred in the eastern RTOs; they also lack the disincentives that prevent

some utilities from promoting DR.⁸⁵ The fact that some parts of the Midwest ISO have much less DR than others suggests that the utilities in those areas have lagged in developing cost-effective DR, and that CSPs could help to fill those gaps. Moreover, FERC's recent Order 719 requires the RTOs to accommodate CSPs to the extent allowed by state or local regulatory restrictions. The Midwest ISO's compliance filing is due on April 28, 2009.

However, this recommendation is made subject to several caveats. First, the degree to which CSPs could disrupt LSE planning and trading needs to be considered. Second, the relative costs of accommodating CSPs compared with the benefits to the market must be further examined. The costs include charges to other customers, LSEs and market participants to fund payments for "negawatts" (including phony negawatts if the customer baseline load (CBL) does not accurately measure what an end-user would have consumed but for its response to price signals), increased operational costs of incorporating resources that are not fully controllable, predictable, or nodally dispatched, and administrative costs. Administrative costs include the costs of administering programs and modifying the Midwest ISO's tariff, business practices, market software, and settlement systems. (Minor modifications might be needed to allow CSPs to offer demand reductions at the same commercial pricing node as the host LSE; it will also be necessary to implement CBL and settlement mechanisms in the software. Third, payments to CSPs should avoid the issue of "double dipping," as discussed above. Determining the appropriate retail rate offset is not necessarily a straightforward matter for those end-use customers whose retail rates are not transparent to the Midwest ISO.

In principle, the Midwest ISO already allows access for CSPs by enabling them to offer demand response resources (DRR) in the energy market. DRR offers are based on load reductions in the Midwest ISO footprint, and are treated like generation in every respect. However, since the Midwest ISO has no CBL methodology or a standardized M&V protocol in place, in practice only very small amounts of DRR – approximately 15 MW, all of which is behind-the-meter

⁸⁵ Utilities disincentives may be addressed as state commissions become sympathetic to the problem and implement rate designs and other regulatory vehicles to allow utilities to decouple fixed cost recovery from sales volume. Furthermore, many commissions are considering incentive ratemaking that allows the LSE to share in the benefits of DR and energy efficiency. EEI is working with NARUC on these issues also.

generation, whose output can be metered easily – participate in the energy market. Incorporating load reductions that are *not* supported by behind-the-meter generation as DRR that can participate in energy markets requires a CBL methodology and special M&V protocols. A CBL methodology establishes the reference level from which load reductions are defined and measured (as the difference between the baseline and actual load). M&V protocols include procedures used to substantiate the claimed amount of load reductions. Fully enabling CSPs in the “supply curve” model will require developing a robust CBL methodology and M&V protocols.⁸⁶

As the Midwest ISO begins its transition toward more complete integration of economic demand response, it might also want to consider engaging in the following three related activities. First, estimate the value of economic DR in the region. Second, develop an internal capability for demand forecasting and introduce price in the demand forecasting process. And third, consider including technology-enabled dynamic pricing in its resource adequacy construct.

VIII.A OUTLINE OF A ROADMAP

The following is a high-level roadmap for enabling CSPs in the “supply curves” model as at least a bridge to a long-term ideal in which the states widely implement dynamic retail pricing. Developing a fully integrated supply curves model with CSP participation may require a substantial amount of time and resources. For example, ISO-NE estimated that fully integrating its day-ahead load response program would have required up to two years to complete.⁸⁷ Since the Midwest ISO is further along in its DR accommodation than ISO-NE was at the time, we estimate that implementing the remaining enabling elements would take less time. We recommend the following steps over the next 1-2 years:

- Conduct a stakeholder process to develop a CBL methodology and M&V protocols – 6 months.

⁸⁶ The North American Energy Standards Board (NAESB) has already proposed M&V wholesale standards that are out for public comment that will be considered by the WEQ Engineering Subcommittee, having passed out of the DSM subcommittee last month.

⁸⁷ Compliance Filing of the New England Power Pool Participants Committee and ISO New England Inc., FERC Docket No. ER05-627-000, February 18, 2005.

- Develop business rules and integrate them into the settlement software – 4 months.
- Consider developing a separate electronic interface for submission of DRR offers; establish whether the current market interface accommodates all characteristics of DRRs. For example, PJM created the eLoad Response interface for demand resources that is used to automate the registration process, standardize data entry for settlement, automate notifications, and interact with PJM’s market and settlement systems.
- Consider enabling DRR to set the real-time market price; evaluate the costs of implementation against its benefits (which may be limited by the number of participants who are able to meet all the necessary requirements, such as real-time telemetry, nodal pricing, unambiguous CBL; incremental and decremental loadability).
- Engage state commissions and utilities in discussions about the benefits of DR. Also discuss dynamic pricing issues and necessary steps to bring about dynamic retail rates, the first-best solution.
- Assess the implications of economic demand response on demand forecasting, resource adequacy planning, and resource costs.

The amount of time to implement each of above tasks depends on the current state of demand resources in Midwest ISO markets. For example, LSEs must already provide the Midwest ISO specific testing procedures for verifying the ability of demand resources that are used as capacity resources to meet the resource adequacy requirement, pursuant to Module E of the Midwest ISO Tariff. Similarly, participants in the Midwest ISO’s Emergency Demand Response initiative submit their proposed M&V procedures. The enabling role of the Midwest ISO is to standardize CBL, M&V, and other procedures. The Midwest ISO under the guidance of the Demand Response Working Group and the Supply Adequacy Working Group are already in various stages of development for many of these steps.

APPENDICES

APPENDIX A: FACTORS AFFECTING THE ECONOMIC POTENTIAL FOR DR

While state regulatory policy and RTO business practices are critical for enabling DR, the *economic potential* for DR depends on factors largely beyond the RTOs' and regulators' immediate control: the geographical and economic context, and electricity supply and demand conditions.

ELECTRICITY SUPPLY AND DEMAND CONDITIONS

RTOs and state regulators have some influence over supply and demand conditions, but at any point in time, the amount of resources and the level of demand must be taken as given. In surplus conditions, new resources are not needed. Investors can be expected to develop DR and other new resources only in scarcity conditions (and if market signals are visible and appropriate, rewards are available).

The fundamental value of DR – and the development of DR resources – depends primarily on the scarcity of supply. DR is critical in regions with scarce supply, and it has relatively little value in markets with surplus capacity. PJM has seen a recent rise in DR in locations where the market is becoming tight (after years of surplus). In ISO-NE, most new DR was created in Southwest Connecticut, where supply shortages are compounded by a weak transmission system that could support limited imports and no new generation interconnections.⁸⁸ Similarly, in PJM's capacity auctions, proportionally more new DR was added in the Eastern and Southwestern MAAC Locational Delivery Areas as a percentage of peak load.⁸⁹

The overall level of current or recent reserve margins in each RTO are summarized below:

- Midwest ISO: 19.9 percent; (Midwest ISO 2006 SOM Report, Table 1, Page 18);
- PJM: 18 percent (PJM 2006 Load Forecast Report; PJM 2006 SOM Report, Pt I, Page 27, Table 1-5) adjusted to include imports;
- ISO-NE: 21 percent (2007 CELT, Page 1) adjusted to include imports;

⁸⁸ ISO New England, 2007 Regional System Plan.

⁸⁹ 2009/2010 and 2010/2011 RPM Base Residual Auction Results, PJM.

- NYISO: 18.1 percent (2006 and 2007 Load and Capacity Reports; Review of NYISO Summer Peak Models – 2000 to 2006, NYISO Resource & Load Adequacy, January 22, 2007) adjusted to include imports.

In addition, just as with generation, DR needs sufficient and stable enough prices in capacity markets in order for the incentive provided by capacity markets to be sufficient to induce entry. For example, some analysts and market participants claimed that the clearing price in ISO-NE's recent Forward Capacity Auction was not sufficient to sustain large upfront investments in new DR if the low prices continue to persist.⁹⁰

ECONOMIC AND GEOGRAPHIC FACTORS

The geographical and economic context of the RTO is an important factor over which the RTO has no control. Geography is an important influence because of the underlying weather patterns and hence the usage and penetration of technologies like air conditioning. For example, the Midwest Census Region where most of the Midwest ISO's footprint lies has residential air conditioning penetration of approximately 83 percent while the California has residential air conditioning penetration of approximately 48 percent.⁹¹ Clearly, the ability to obtain DR via direct load control of air conditioning has, at the face of it, more potential in the Midwest ISO than in CAISO.⁹² Likewise, the underlying economic background of the RTO region will influence the type and amount of DR that is available. For example, ERCOT has a very successful DR program in large part due to the size of the industrial base in its territory.⁹³ Without that underlying industrial base, ERCOT's DR program would probably be much smaller.

⁹⁰ The market clearing price of capacity in ISO-NE's recent Forward Capacity Auction for the 2010/2011 delivery year was equal to the floor price of \$4.50/kW-month, reflecting an excess of supply.

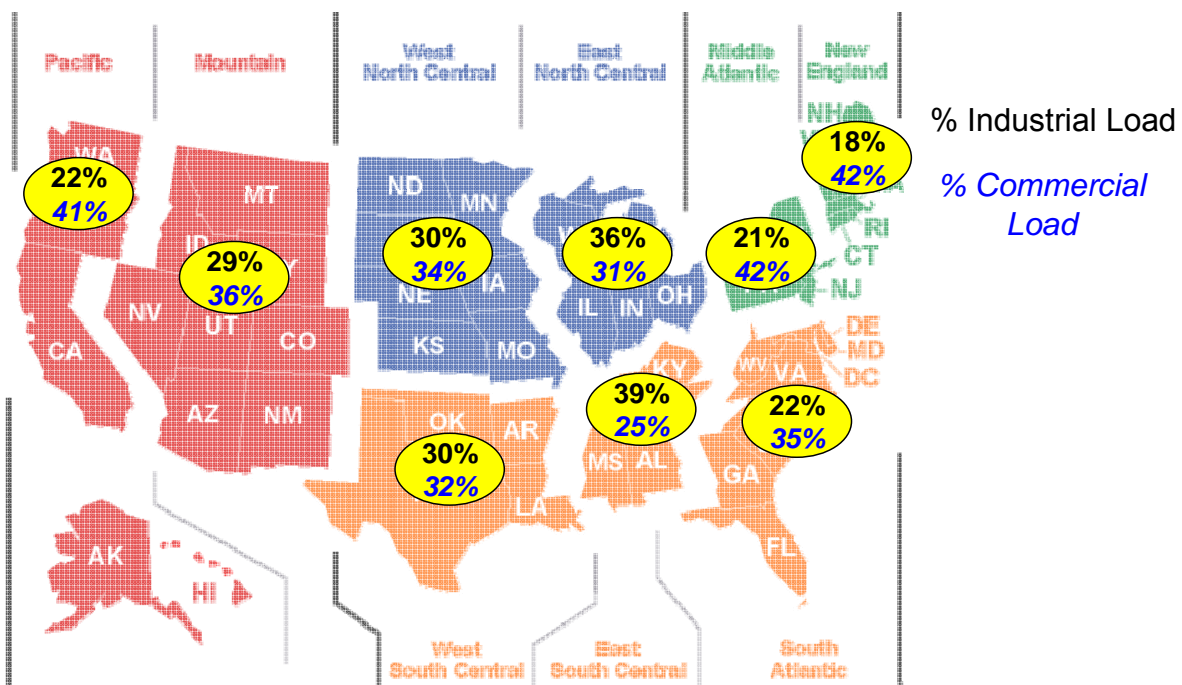
⁹¹ Based on EIA's 2001 Residential Energy Consumption Survey (RECS), Form EIA-457A.

⁹² Clearly, the amount of air conditioning on direct load control is influenced by a variety of factors beyond the sheer amount of air conditioning penetration in a particular ISO. However, the amount of air conditioning penetration gives the "market size" for air conditioning direct load control.

⁹³ Robert Earle and Ahmad Faruqui, "Demand Response and the Role of Regional Transmission Operators", *2006 Demand Response Application Service*, Electric Power Research Institute, 2006.

The economic and geographic context of the RTO can be a key determinant in the amount of DR available. Figure 13 shows the relative level of large industrial load. As can be seen from the figure, industrial load represents 30 percent of total load in the West South Central census division, which is roughly the same as in Texas. This relatively large industrial load is reflected in the size of ERCOT's industrial DR programs. By contrast, industrial load represents less than a fifth of total load in New England, and therefore the potential of such loads to provide DR is much lower.

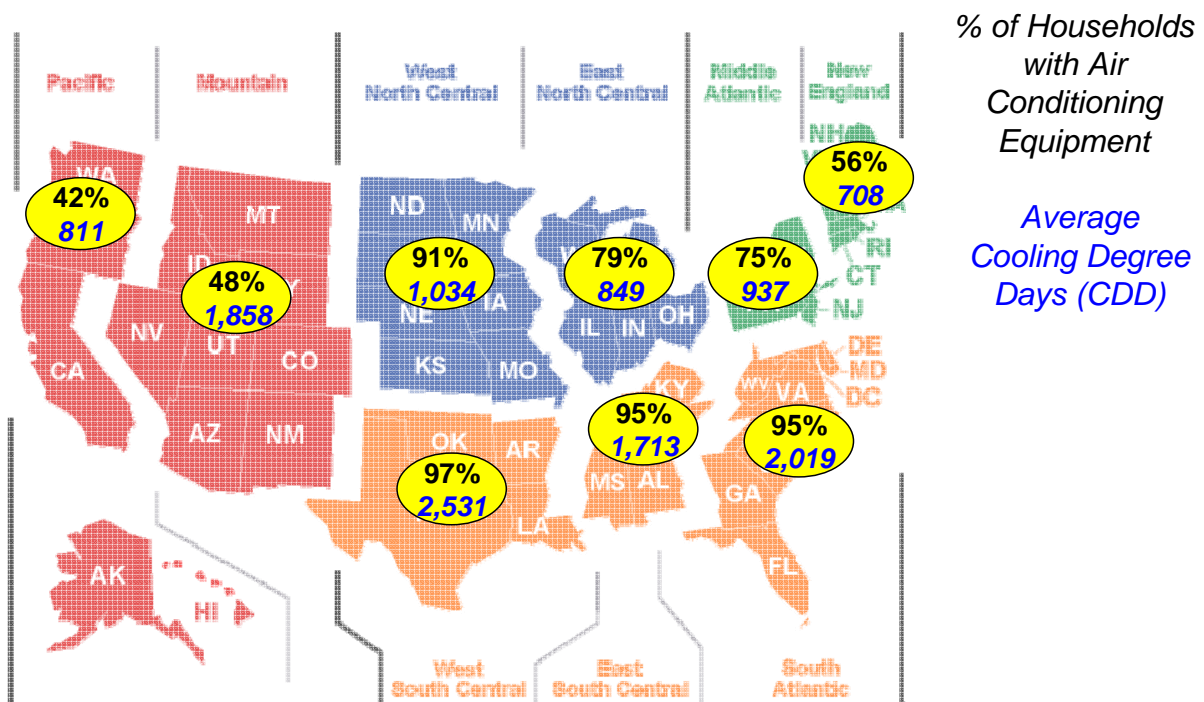
**FIGURE 13: INDUSTRIAL LOAD AS A PERCENTAGE OF TOTAL LOAD
BY CENSUS DIVISION**



Source: Census regions and divisions defined by EIA; See http://www.eia.doe.gov/emeu/rep/maps/us_census.html. Supplemental Tables to the Annual Energy Outlook 2007, Tables 1-9; <http://www.eia.doe.gov/oiaf/aeo/supplement/index.html>

Residential A/C penetration is depicted in Figure 14 below.⁹⁴ As the figure shows, the Midwest has a much higher A/C penetration and higher A/C loads (based on cooling-degree-days), and hence a greater potential for DR from A/C load, than for example CAISO or ISO-NE.

FIGURE 14: RESIDENTIAL AIR-CONDITIONING SATURATION BY CENSUS DIVISION



Source: Census regions and divisions defined by EIA; See http://www.eia.doe.gov/emeu/reps/maps/us_census.html. Air conditioning saturation based on survey data in 2001 Residential Energy Consumption Survey; Form EIA-457A (2001)--Household Questionnaire; OMB No.: 1905-0092, Expiring February 29, 2004.

⁹⁴ **Source:** Census regions and divisions defined by EIA; See http://www.eia.doe.gov/emeu/reps/maps/us_census.html. Air conditioning saturation based on survey data in 2001 Residential Energy Consumption Survey; Form EIA-457A (2001)--Household Questionnaire; OMB No.: 1905-0092, Expiring February 29, 2004.

APPENDIX B: METHODOLOGY FOR THE MAXIMUM ACHIEVABLE POTENTIAL DR PROJECTION

The DR forecast was developed for three specific program types:

- *Direct Load Control (DLC)*: Customer end-uses are directly controlled by the utility and are shut down (or reduced to a lower consumption level) during emergency conditions. For our purposes, we model an air conditioning DLC program.
- *Interruptible Service*: Customers agree to reduce consumption to a pre-specified level, or by a pre-specified amount, during emergency conditions.
- *Dynamic Pricing*: Includes time-varying rates that can be “dispatched” during emergencies or high-priced hours to encourage peak reductions. Advanced Metering Infrastructure (AMI) must be in place to offer these rates. Examples include Critical Peak Pricing (CPP) and Real Time Pricing (RTP).

These programs are further divided among the residential, and commercial and industrial (C&I) classes, with the exception of interruptible service which is only available for C&I customers. This amounts to five distinct programs that were modelled in the forecasts.

There are three basic steps to developing the DR forecast. First, an estimate of the average customer-level demand reduction is developed. Then, a forecast of the number of participating customers is created. The customer-level impacts are multiplied into this forecast to produce the system-wide peak and energy reductions. Below, these three steps are described in detail for each of the three DR program types that were modelled.

DIRECT LOAD CONTROL

Customer-Level Impacts

For residential customers, the peak reduction from the average customer participating in a DLC program was set equal to 1 kW, based on the fact that industry estimates range from around 0.8 kW to 1.2 kW. This impact estimate is a function of the average size of the customer’s central

air conditioning unit. For commercial customers, the peak reduction would be larger and was approximated at 2 kW per customer.

The total change in energy consumption induced by the DLC program is a function of the number of hours over which this peak reduction is achieved. We assumed four emergency events each lasting five hours, for a total of 20 hours per year during which the DLC program is activated. Multiplying this into the customer-level impacts produces a 20 kWh per kW reduction, which equals a 20 kWh/year reduction per residential customer and a 40 kWh/year reduction per C&I customer.

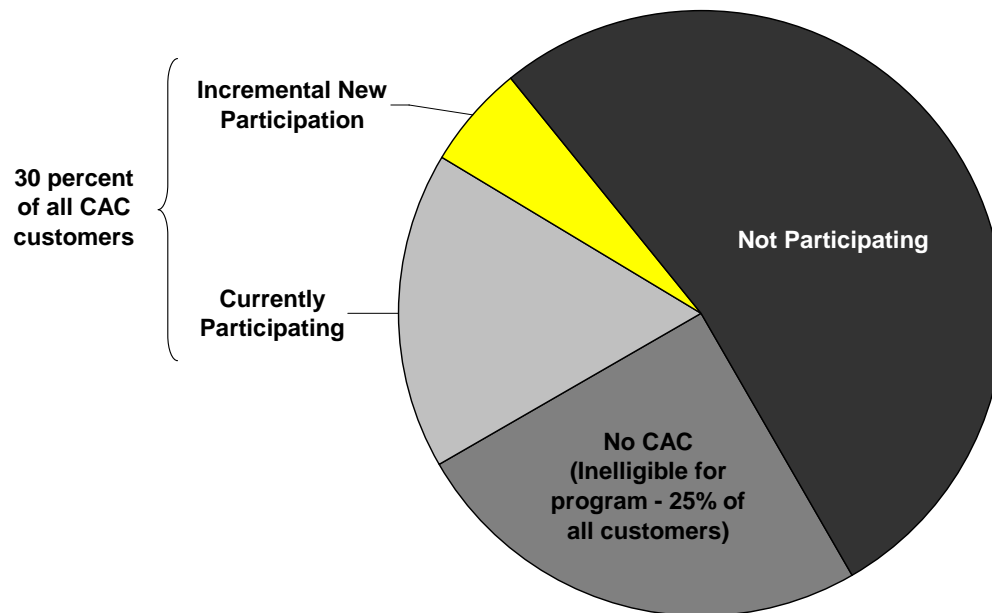
Participation Forecast

The participation forecast depends on a number of factors, including the number of existing customers, the percent of those customers eligible to participate in the program, the customers *already* participating in the program, and the assumed participation rate. The following steps illustrate how these factors interact to produce the participation forecast.

1. **Determine the number of customers in MISO.** To approximate the total number of customers, we relied on EIA Form 861 data, which provides the number of residential customers by state and utility. The total for MISO in the year 2007 is 8.4 million. For C&I customers, it is 1.1 million.
2. **Determine the number of customers already participating in DLC.** We first allocated the total expected peak reduction from DLC to customer class based on the population share determined in step 1. We then divided the expected class peak reduction by the average reduction per customer to back out the number of participating customers. The result for 2007 is 1.4 million participating residential customers and 94,000 C&I customers.
3. **Determine the percent of customers with central air conditioning (CAC).** Based on experience working with utilities in other regions of the US, we assumed that 75 percent of residential customers would have CAC, and 100 percent of C&I customers would have CAC. Only customers with CAC are eligible for an air conditioning DLC program.

4. **Estimate customer participation rate.** The next step is to make estimate the percentage of eligible customers who will ultimately enroll in the program. Based on industry experience, utilities have generally forecasted that anywhere from 20 percent to 40 percent of their customers could potentially enroll in a DLC program. For both residential and C&I customers, we have projected a 30 percent participation rate.
5. **Determine the number of new participating customers.** Steps 1 through 4 can be combined together to arrive at the number of new participants. Figure 15 illustrates this step.

FIGURE 15: ILLUSTRATION OF SINGLE YEAR RESIDENTIAL PARTICIPATION FORECAST



The previous steps produced a single year forecast of the DLC participation rate. To produce a forecast over the study horizon (2008 through 2027), we applied this methodology in each year and combined it with the assumption that the residential customer growth rate is 1.2 percent annually. This is based on the average annual housing growth rate in MISO states from 2002 through 2006, using Census data. The C&I customer base was also assumed to grow at this rate. Beginning in 2020, it was assumed that a share of the participating customers would switch over to dynamic pricing to take advantage of more attractive bill savings.

INTERRUPTIBLE SERVICE

The Interruptible Service forecast followed an approach that is very similar to the DLC forecast. The primary difference is that Interruptible Service was only modelled for the C&I customers, as these programs do not allow residential enrollment.

Customer-Level Impacts

The average customer peak reduction from Interruptible Service programs was assumed to be 10 kW. This estimate is based on a review of various utility IRPs and is generally consistent with the MISO program-specific research that we performed as part of its Module E study.

To calculate the per customer energy impacts, we assumed that the same number of events (four) and hours per event (five) in the DLC program would apply to the Interruptible Service program. This similarly produces a 20 kWh per kW energy reduction which translates into 200 kWh/year per C&I customer.

Participation Forecast

Similar to the DLC program, the annual participation in the Interruptible Service program was developed using the following steps:

1. **Determine the number of existing customers in MISO.** As was described in the DLC analysis, the estimate is 1.1 million C&I customers in 2007.
2. **Determine the number of customers currently participating in the program.** This was backed out of the provided Interruptible Service peak reduction forecast and was estimated to be 247,000 customers in 2007.
3. **Assume a participation rate.** 20 percent of all customers are assumed to participate. This is a fairly standard industry assumption for participation in opt-in rate-based programs.
4. **Determine the number of new participating customers.** Similar to the DLC forecast, the number of new participating customers are estimated as follows:

$$\text{New participants} = \text{Total customers} \times \text{participation rate} - \text{existing participants}$$

As in the DLC forecast, a 1.2 percent annual customer growth rate is applied to arrive at the final Interruptible Service participation forecast. Similar to the DLC program, we have assumed that participation ramps down beginning in 2020 to account for customers switching to more attractive dynamic rates.

DYNAMIC PRICING

Across the United States, dynamic pricing is expected to play an increasingly important role in utility DR efforts.⁹⁵ Many utilities are currently conducting pilots to measure the impacts of dynamic pricing and to understand the financial benefits of investment in AMI, or “smart meters.” In California, all three of the three investor-owned utilities have already received approval to invest billions of dollars in the installation of these meters. It seems plausible that over the next two decades, utilities in the MISO area would pursue similar programs. Thus, we have included dynamic pricing as another potential source of new DR in the forecast.

Development of the dynamic pricing forecast follows the same general framework of the DLC and Interruptible Service programs. We determine customer-level impacts and then multiply these into an estimate of the number of participating customers to arrive at the final impacts forecast.

Customer-Level Impacts

Customer-level peak impacts were estimated for four classes of customers:

- Residential
- C&I less than 20 kW
- C&I between 20 kW and 200 kW
- C&I greater than 200 kW

The expected peak reductions for these customers assumed that some of the customers were equipped with enabling technology such as a smart thermostat, which would automatically reduce consumption at certain end-uses in the event of a critical event (or high-priced day). The

⁹⁵ Federal Energy Regulatory Commission, “Assessment of Demand Response & Advanced Metering,” September 2007.

average reductions were derived from a recent study in California on the impacts of dynamic pricing (the California Statewide Pricing Pilot, or “SPP”).⁹⁶ These average peak reductions are summarized in Table 11.

TABLE 11: SUMMARY OF AVERAGE CUSTOMER-LEVEL PEAK REDUCTIONS DUE TO DYNAMIC PRICING

	In-Class Allocation	Customer Peak Reduction
Residential		
No Technology	70%	13%
Enabling Technology	30%	27%
<i>Wtd Average</i>		17%
C&I (< 100 kW)		
No Technology	60%	0%
Enabling Technology	40%	13%
<i>Wtd Average</i>		5%
C&I (100 kW to 350 kW)		
No Technology	60%	5%
Enabling Technology	40%	10%
<i>Wtd Average</i>		7%
C&I (> 350 kW)		
No Technology	60%	7%
Enabling Technology	40%	13%
<i>Wtd Average</i>		9%

Some experiments on dynamic pricing, including the California SPP, have suggested that the foregone consumption during the peak period is actually shifted to the off-peak period. This offsets the peak reduction and leads to a negligible overall conservation impact. Ultimately, there is not yet a consensus on how total consumption is affected. For this reason, we have assumed no change in the overall consumption level due to dynamic pricing. Thus, the kWh per kW reduction is zero.

⁹⁶ We have used the impacts from a CPP rate as the basis for our analysis. Further work would need to be done to estimate the impacts of other rate designs and to model customer elasticities at a more detailed level.

Participation Forecast

The following steps were taken to develop the participation forecast for each class:

1. **Determine the size of the existing population.** As in the DLC forecast, the residential population in 2007 is assumed to be 8.4 million. The C&I population is 1.1 million and is allocated to the three C&I classes according to their approximated share of the system peak.
2. **Identify the percentage of the population not enrolled in an existing DR program.** The customers enrolled in an existing DR program were previously calculated for DLC and Interruptible Service. These customers are considered to be ineligible for dynamic pricing, since they would otherwise be overpaid for the load reductions they are providing. However, after 2020, a share of the customers currently enrolled in DLC or Interruptible Service are assumed to drop out of those programs and join the pool of customers eligible for dynamic pricing.
3. **Identify the percentage of the population equipped with AMI.** Currently, customers in MISO do not generally have AMI, so we have assumed that there will be a lag in its rollout to customers. Beginning in 2008, it will incrementally be provided to customers at a rate of around 10 percent per year, so that all customers have AMI by 2018. The large (greater than 200 kW) C&I customers are assumed to already be equipped with meters that allow dynamic pricing.
4. **Assume a participation rate.** Ultimately, we assume that 80 percent of residential and C&I customers could enroll in dynamic pricing. This is considered to be the achievable participation rate when dynamic pricing is offered on a default, or opt-out basis. Participation ramps up to this level between 2010 and 2017.
5. **Combines steps (1) through (4) to produce the forecast of participating customers.** The combination of steps (1) through (4) produces an annual forecast of customer participation in dynamic pricing. C&I impacts are aggregated across the three classes.