

Commission is opening this case to investigate how to achieve its new responsibilities under the MEEIA, within the background of FERC policies that eliminate barriers to DR and that direct MISO and SPP to accommodate state policy regarding retail customer demand-side activity (MO PSC 2010).

DR is gaining greater acceptance among both utilities and regulators in the United States. A 2006 FERC survey found that 234 "entities" were offering direct load control programs and the FERC's assessment noted that "there has been a recent upsurge in interest and activity in DR nationally and, in particular, regional markets" (FERC 2006).⁵³ The recent proliferation of DR offerings has been promoted in part by utilities hoping to reduce system peaks while offering customers more control over electric bills and in part by regulators. Although federal legislation has not been the driver behind the trend, it is one of many indications, at all levels of government and industry, of the growing support for DR.⁵⁴

Many states experience significant reductions in peak demand from Demand-Side Management (DSM) programs (which include DR programs). Regulatory filings show that California experienced 495 MW in peak demand reductions in 2005 (1% of total peak demand); New York experienced 288 MW reductions in 2005 (1% of total peak demand); and Texas experienced 181 MW in reductions in 2005 (1% of total peak demand) from DSM programs. These results are annual values that do not consider the cumulative (i.e., year-to-year) impacts that accrue over the lifetimes of the conservation measures. Therefore, cumulative percentage reductions in peak demand are much higher than the annual figures stated.

Assessment Methods

As has been shown in numerous other jurisdictions across North America, well-designed DSM programs incorporating DR strategies represent an effective and affordable option for reducing peak demand and meeting growing demand for electricity. This effort estimated conservative peak demand reduction for Missouri using local energy use characteristics, demographics, and forecast peak demand, assuming relatively basic DR strategies comprising responsive reductions in demand. The following research approach was used to conduct the analysis:

- Review of existing information regarding Missouri's customer base including:
 - Customer counts and average annual energy consumption by market segment;
 - Forecasts of future energy consumption and customer counts by market segment;
 - Previous DSM planning and potential studies.
- Review of additional publicly-available secondary sources including:
 - U.S. DOE's Commercial Building Energy Consumption Survey (CBECS) and Residential Energy Consumption Survey (RECS) data;
 - Previous studies relevant to the current effort completed by Navigant Consulting in other regions as well as entities in other jurisdictions.
- Development of baseline profiles for residential and commercial customers. These profiles include current and forecast numbers of customers by market segment and electricity use profiles by segment.

⁵³ The FERC report uses the term "entities" to refer to all types of electric utilities, as well as organizations such as power marketers and curtailment service providers.

⁵⁴ The federal Energy Policy Act of 2005 (EPAc) directs the Secretary of Energy to "identify and address barriers to the adoption of demand response programs," and the Act declares a U.S. policy in support of "State energy policies to provide reliable and affordable demand response services." EPAc directed FERC to conduct its survey of DR programs and also directed the U.S. Department of Energy to report on the benefits of DR and how to achieve them (USDOE 2006). Separately, a *National Action Plan for Energy Efficiency*, which advocates DR and other efficiency efforts, was developed by more than 50 U.S. companies, government bodies, and other organizations, including co-chairs Diane Munns, President of NARUC and Jim Rogers, President and CEO of Duke Energy (USEPA 2006). Other utility industry members of the Leadership Group included Southern Company, AEP, PG&E, TVA, PJM Interconnection, ISO New England, and the California Energy Commission.

- Incorporation of ACEEE baseline data and reference case into analysis.
- Obtaining state-level data when possible and estimation of information for the State of Missouri, when state-level data was not available.
- Development of a spreadsheet approach for estimating peak demand reduction potential associated with the DR programs/technologies deemed to be most applicable to Missouri. Estimates are developed for three scenarios—low, medium and high case scenarios.
- Telephone calls with ACEEE staff and industry professionals to discuss assessment processes and legislative, regulatory, and other factors specific to the State of Missouri.
- Incorporation of all sources of information and references into report, noting on each figure the source of the information.
- Revision of draft report based on comments from ACEEE, industry specialists and utility commenters.

The DR potential estimated used historical data and experience to obtain curtailment levels. This potential is assumed to be the achievable potential that would be cost effective, given the range of incentives that are typically required and the range of the utilities' avoided costs. A cost-effectiveness analysis was not performed for this study. Sufficient incentives could be provided to customers to encourage load reductions while maintaining a cost-effective program. A study by KEMA projected avoided costs of approximately \$108 per kW for 2011 (KEMA 2011).

State of Missouri—Background

A sound strategy for development of DR resources requires an understanding of Missouri's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

Missouri utilities serve a population of almost 6 million, and generates over 91 million megawatt hours of electricity (EIA 2009). Missouri had a system peak load forecast of 17,739 MW in 2009 (KEMA 2011). Electricity demand has grown an average of 3% per year over the period 1990 to 2008, fluctuating moderately (EIA 2009).

Coal-fired plants in Missouri supplied about 81% of State electricity generation in 2008 (EIA 2009). Missouri has been and likely will continue to be an importer of energy: Missouri imported more than 99 percent of the coal its power plants burned in 2008—mainly from Wyoming (UCS 2011).

45% of the total sales in Missouri are attributed to Union Electric Co. Kansas City Power & Light Co and KCP&L Greater Missouri Operations each contribute 10%. The five largest electricity retailers in Missouri are the following entities, with percent contribution in parentheses:

1. Ameren Missouri (45%)
2. Kansas City Power & Light Co (KCP&L) (10%)
3. KCP&L Greater Missouri Operations (KCP&L GMO) (10%)
4. Empire District Electric Co (5%)
5. City Utilities of Springfield (4%)

Assessment of Utility DR Activities

This section outlines existing DR programs currently being offered to customers in Missouri, by utility.

Ameren Missouri

Ameren Missouri offers time-of-use rates to residential customers (but has low participation) and a 'Peak Power Rebate Program' in which participating C&I customers get paid for voluntarily reducing electricity use during peak times. Minimum participation requirements include:

- Be on rate 3(M), 4(M), or 11(M)
- Have the ability to reduce load by at least 200 kilowatts (kW)
- Have an interval meter with communications equipment
- Have a computer with Internet access and a phone
- Have a plan that can reduce your electric demand.

The C&I program started in 2009 but did not call on participants in 2010 and is not anticipating calling on customers in 2011.

Ameren Missouri launched a similar incentive program to residential customers in '09, but the program has been discontinued.

Kansas City Power & Light Co (KCP&L)

KCP&L currently offers:

- The Energy Optimizer Program: For residential and small business customers, KCP&L offers a free programmable thermostat that customers can control remotely via the Internet. Customers partner with the utility to control peak demand. On the hottest summer weekdays, when electricity demand is greatest, KCP&L will adjust the thermostat setting up a few degrees for a short period to reduce air conditioning load.
- Real-Time Pricing Program: Commercial or industrial customers are able to buy electricity at marginal cost-based prices, shift usage to lower cost periods and reduce load to avoid expensive periods.
- The MPower Program: Commercial and industrial customers can manage their load to off-peak times. As of April 2011, there is a waiting list to participate in this program.

Empire District Electric Co

For industrial customers, Empire District Electric Co offers participation in a Special Transmission Service Contract: Praxair. This entails interruptible demand of at least 5600 kW, a minimum of 30 minutes notice, and no more than 400 hrs of DR over 12 months.

Summary of DR Programs in Missouri offered to Commercial and Industrial Customers

Table B-2 summarizes the load reductions achieved in 2008 from DR programs offered to Missouri's Commercial and Industrial (C&I) customers

Table B-2. Enrollment in and Reductions from C&I DR Programs in Missouri in 2008

Name	Ownership	Program	Customers Enrolled (#)	MW Enrolled	Actual Peak Reductions in 2008 (MW)
White River Valley Electric Cooperative, Inc.	Coop	Interruptible Rate	40	24	16
Columbia Water & Light Dept.	Muni	Load Shedding	23	21.753	7.445
Columbia Water & Light Dept.	Muni	Load Management	774	21.753	0.23
Columbia Water & Light Dept.	Muni	High Load Factor Rider	3	8.202	1.082
Empire District Electric Company	IOU	Special Transmission Service Contract: Praxair	1	8.1	7.6
Columbia Water & Light Dept.	Muni	Thermal Storage Rider	1	7.173	0.819
Cuivre River Electric Cooperative	Coop	Peal Alert Demand Curtailment	12	6.8	5.2

Source: Navigant Consulting, Forthcoming

Assessment of Current State Policies Affecting DR

In Order 719 and Order 719-A issued by the Federal Energy Regulatory Commission (FERC), the FERC enacted new rules aimed at eliminating barriers to demand response while achieving comity between state and federal regulatory policy concerning demand response in areas served by organized wholesale electric markets.

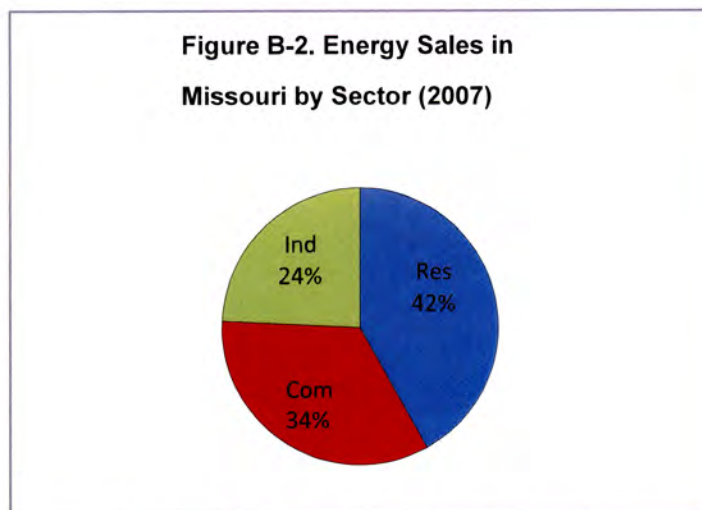
The Missouri Energy Efficiency Investment Act (MEEIA), Senate Bill 376, declares that the policy of Missouri is to value demand-side investments equal to traditional investments in supply and delivery infrastructure. Among other provisions, the law requires the Commission to direct the implementation of demand-side programs "with a goal of achieving all cost effective demand-side savings," coupled with timely cost recovery and alignment of utility financial incentives with energy efficiency. The Commission has been investigating how to achieve its new responsibilities under the MEEIA, within the background of FERC policies that eliminate barriers to DR and that direct MISO and SPP to accommodate state policy regarding retail customer demand-side activity. The Commission is investigating if any Missouri statute, law, or regulation prohibit or restrict electric utility customers from participating directly or indirectly through aggregator of retail customers (ARCs) in DR bidding programs and other issues concerning implementation of DR (MO PSC 2010).

Many states have put in place renewable portfolio standards (RPS) to ensure that a minimum amount of renewable energy is included in the portfolio of the electricity resources serving a state. Many RPS include demand side options among the means by which the standards can be met. Missouri's RPS objective of 15% by 2021 was enacted July 2007. Credits towards this goal can be achieved through implementation of energy-efficient practices, defined as "verifiable reductions in energy consumption, or verifiable reductions in the rate of energy consumption growth." Eligible energy efficient improvements include pricing signals, electronic controls, education, information, infrastructure improvements, and the use of high-efficiency equipment and lighting (APPA 2010).

In November 2008, voters passed a ballot initiative that establishes a mandatory RPS for investor-owned utilities of 2% by 2011 and 15% by 2021. It does not define renewable resources or include any references to energy efficiency (APPA 2010).

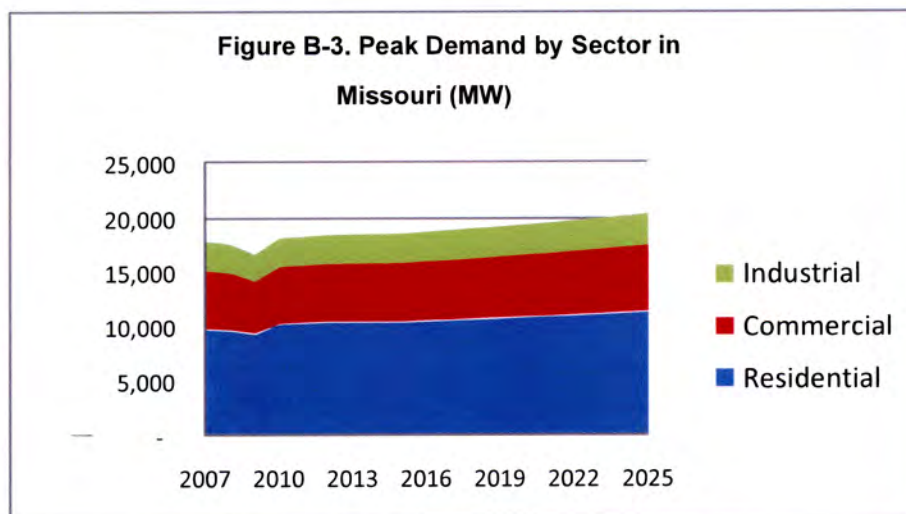
Energy and Peak Demands

Use of energy in Missouri is distributed to end use categories as follows: 42% residential, 34% commercial, and 24% industrial sectors (see Figure B-2).



Source: ACEEE Missouri Reference Case

In 2007, the total summer peak load was 17,801 MW and is projected to grow an average of 0.76% per year through 2025. Figure B-3 displays peak demand by sector. In 2007, residential peak demand was estimated at 9,580 MW; commercial was 5,338 MW; and industrial was 2,642 MW.



Source: ACEEE Missouri Reference Case

Smart Grids and Advanced Metering Infrastructure (AMI)

The EPACT provisions for DR and Smart Metering have led to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI).

Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. The end user is equipped with real-time communication between the consumer and utility allowing optimization of a consumer's energy usage based on environmental and/or price preferences (for example, critical peak pricing and time of use rates).

AMI provides:

- Two-way communication between the utility and the customer through the customer's smart meter.
- More efficient management of customer outages (location, re-routing).
- More accurate meter reading (minute, 15 minute intervals).
- More timely collection efforts (real time).
- Improved efficiency in handling service orders.
- More detailed, timely information about energy use to help customers make informed energy decisions (real time).
- Ability to reduce peak demand.
- More innovative rate options and tools for customers to manage their bills.

Smart Energy Pricing provides:

- Incentives to customers to shift energy away from critical peak periods
- The ability for customers to save on their electricity bills.
- Lower wholesale prices for capacity and transmission—in the longer term.
- Improved electric system reliability, as demand is moderated.
- Potential to defer new transmission and generation.

The Smart Grid is comprised of multiple communication systems and equipment, which interoperability is crucial. Not all communication protocols are applicable to every utility's geography; therefore, pilots are essential in testing the equipment and communication software for various geographies. Furthermore, the identification of those geographic regions with the best return on investment during a pilot will aid the staged implementation plan. Standards are continuing to be researched through organizations including: 1) IntelliGrid—Created by the Electric Power Research Institute (EPRI); 2) Modern Grid Initiative (MGI) is a collaborative effort between the U.S. Department of Energy (DOE), the National Energy Technology Laboratory (NETL), utilities, consumers, researchers, and other grid stakeholders; 3) Grid 2030—Grid 2030 is a joint vision statement for the U.S. electrical system developed by the electric utility industry, equipment manufacturers, information technology providers, federal and state government agencies, interest groups, universities, and national laboratories; 4) GridWise—a DOE Office of Electricity Delivery and Energy Reliability (OE) program; 5) GridWise Architecture Council (GWAC) was formed by the U.S. Department of Energy; and 6) GridWorks—A DOE OE program.

Developments in technology allowing real time signaling and automated response will improve DR capabilities. However, existing technology exists for successful DR implementation and it is important to point out that there are no technology obstacles to effective DR.

Assessment of DR Potential in Missouri

This section examines and quantifies DR potential in Missouri. This first section outlines the general DR program categories, while the next two sections outline the DR potential in the residential and commercial /industrial sectors, respectively. Next, we discuss the load reduction potential from backup generation and then explain the issues surrounding rate pricing, even though benefits from this form of DR are not quantified in this analysis. Finally, the sixth section concludes with a summary of DR potential in Missouri.

Demand Response Program Categories

For the purposes of assessing DR alternatives, the following programs could be employed in Missouri to achieve the DR potential we outlined in this report:

Resource Category	Characteristics
Direct Load Control (DLC)	Direct load control (DLC) programs have typically been mass-market programs directed at residential and small commercial (<100 kW peak demand) air conditioning and other appliances. However, an emerging trend is to target commercial buildings with what has become known as Automated Demand Response or Auto-DR. Increased use and functionality of energy management systems at commercial sites and an increased interest by commercial customers in participating in these programs is driving growth in automated commercial curtailment in response to a utility signal. The common factor in these programs is that they are actuated directly by the utility and require the installation of control and communications infrastructure to facilitate the control process.
Callable Customer Load Response	With this type of program, utilities offer customers incentives to reduce their electric demand for specified periods of time when notified by the utility. These programs include curtailable and interruptible rate programs and demand bidding/buyback programs. Curtailable and interruptible rate programs can be used as "emergency demand response" if the advanced notice requirements are short enough. All customer load response programs require communications protocols to notify customers and appropriate metering to assess customer response.
Scheduled Load Control	This is a class of programs where customers schedule load reductions at pre-determined times and in pre-determined amounts. A variant on this theme is thermal energy storage which employs fixed asset technology to reduce air conditioning loads consistently during peak afternoon load periods.
Time-Differentiated Rates	Pricing programs can employ rates that vary over time to encourage customers to reduce their demand for electricity in response to economic signals—in some cases these load reductions can be automated when a price trigger is exceeded. An example is a critical peak price which is "called" by the utility or system operator. In response to this critical price, residential customers can have AC cycling or temperature setbacks automatically deployed. Similar automated responses can be deployed by commercial customers. These rate programs are not analyzed for this assessment, but are further discussed in the section below on "Pricing and Rates."

DR for Residential Customers

Air conditioner and other appliance direct load control (DLC) is the most common form of non-price-based DR program in terms of the number of utilities using it and the number of customers enrolled. According to FERC's 2006 assessment of DR and advanced metering, there are 234 utilities

(including municipalities, cooperatives, and related entities) with DLC programs across the United States. Approximately 4.8 million customers are participating in DLC programs across the country (FERC 2006).

The prominent and growing role of air conditioning in creating system peaks makes it a high-profile candidate for DR efforts. The advances in DR technology that make AC load management economically viable make AC load control a high-priority program—one that has been proven reliable and effective at many utilities. Pool pumps are also a relatively easy and non-disruptive load that can be controlled for DR purposes.

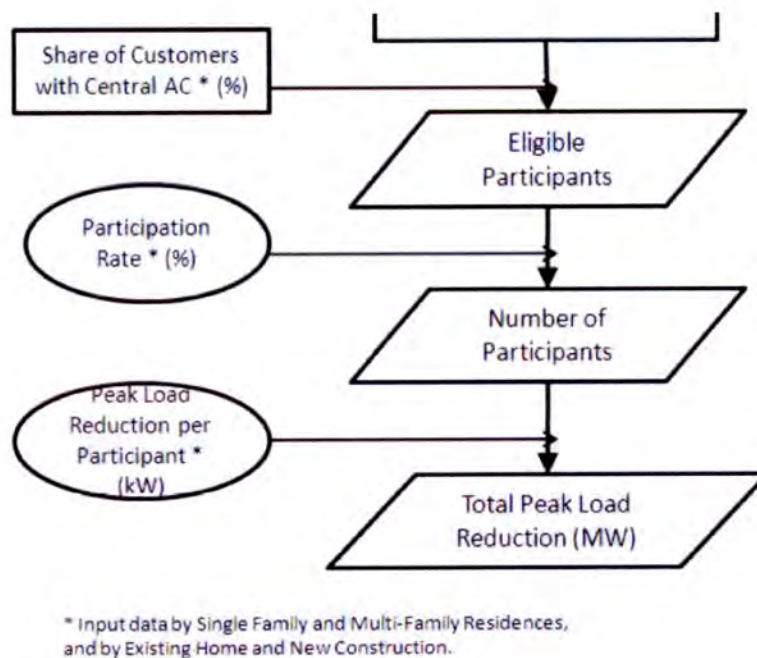
Residential Control Strategies

There are two basic types of control strategies: AC cycling and temperature offset. AC cycling limits ACs being on to a certain number of minutes than they otherwise would have been on. Some techniques limit ACs to being on for 50% of the minutes they would otherwise have been on. A temperature offset increases the thermostat setting for a certain period of time, for a certain number of degrees higher than it would have otherwise been set. This essentially causes the AC compressor to cycle as the temperature set-back reduces the AC demand. Sequential thermostat setbacks, i.e., one degree in hour one, two degrees in hour two, three degrees in hour three, and four degrees in hour four can mimic an AC cycling strategy.

Cycling strategies have evolved where an optimal impact on peak kW demand may be obtained by varying the cycling time across the hours of an event. For example, there may be one hour of pre-cooling followed by 33% cycling in the first hour, 50% cycling in the second hour, 66% cycling in the third hour and dropping back to 33% in the fourth hour. Strategies like this have been deployed in pilot programs at Progress Energy Carolinas (PEC) and in PSE&G's MyPower pilot program. This type of strategy requires that forecasters accurately predict the hour(s) in which the peak system demand will occur.

Assessment of DR Potential in Residential Homes in Missouri

For Missouri, estimates for possible load reductions for residential housing units were obtained by applying the methodology displayed in Figure B-4.

Figure B-4. Residential Peak Load Reduction

The figure shows how load reductions and participations rates are applied to housing data. Items listed in rectangular shapes are factual inputs; items in circular shapes are assumptions; and items in parallelogram shapes are results. The analysis conducted for this study was based on demand response for summer loads, especially air conditioning, since Missouri's major utilities are summer-peaking. However, it should be noted that some mountainous regions in the western portion of the state are winter peaking, and DR programs have targeted electric space and water heating loads.

Load Reductions

Recent surveys show that DLC programs are being implemented by a number of utilities. Load impacts are dependent on many variables. The control strategy used, the outdoor temperature, the time of day, the customer segment, ease of and ability to override control, reliability of communication signals, age and working condition of installed equipment, and local AC use patterns all have significant effects on the load impact. Even within a single program, there is variability in impacts across event days that cannot yet be fully explained. Measuring impacts typically requires expensive monitoring equipment and as a result is often done on small sample sizes.

Even with this variability, a review of reported impacts does show some general consistencies. As expected, impacts increase as the duty cycle goes up. Table B-3 shows the average reported kW impact based on 20 load control impact studies for programs based on the duty cycle used. These results support the oft-quoted rule-of-thumb that the load impact for 50% duty cycling is 1 kW per customer, which is the impact used in this analysis. However, many homes will experience an impact greater than 1 kW, especially newer homes.

Table B-3. Average Load Impacts by Cycling Strategy for AC DLC Programs

Cycling Strategy	Average Load Impact KW/Customer
33%	0.74
45%	0.81
50%	1.04
66%	1.36

Source: Summit Blue 2007b

Customer type also makes a difference. In a few cases where single-family and multi-family impacts were measured separately, multi-family impacts were 60% of single-family, and thus a 0.6kW load reduction is applied in this analysis for multi-family units (Summit Blue 2007b).

Eligible Residential Customers

All residential customers with central air-conditioning that live in areas that can receive control signals are considered eligible for the direct load control program. This includes single family and multi-family housing units. Residential accounts without central AC are assumed to have no participation.

It has been estimated that 87.1%% of Missouri single-family customers have central AC, and 88.6% multi-family customers (Ameren 2010; RLW 2006).

Multi-family housing units often have building tenants which are not the account holders, therefore accounts are often aggregated into buildings. Some accounts have a master meter for the entire building, including tenants. Some accounts are for the "common" building loads (i.e., those loads that are part of a building account such as elevators, A/C (if applicable), lobby lighting, etc.), but individual tenants in these buildings have their own accounts. Therefore, multi-family units often have fewer units with central AC than single family. For the purposes of this analysis, it is assumed that multi-family units have 20% less units than single family.

Residential Participation Rates

Participation rates experienced in AC DLC programs vary across utilities typically from 7% of eligible customers to 40%, depending upon the effort made in maintaining and marketing the program (Summit Blue 2007a). The utilities with the low levels of participation had essentially stopped marketing the program in recent years. Utilities with programs with sustained attention to customer retention or recruitment show higher participation rates than utilities with one-time or intermittent promotion. In Maryland, BG&E's Demand Response Service program anticipates a residential participation rate of 50%, or approximately 450,000 controlled units (BG&E 2007). The pilot phase of this program was conducted from June 1 through September 30, 2007, and 58% received a "smart" load control switch, and 42% had a "smart" thermostat installed (BG&E 2007). One study examined 15 AC DLC programs nationwide and found an average of 24% participation for eligible customers (Summit Blue 2008b).⁵⁵ For this analysis, 3 typical yet conservative scenarios were used: a low scenario of 15% for eligible customers; a medium scenario of 25%; and a high scenario of 35%.

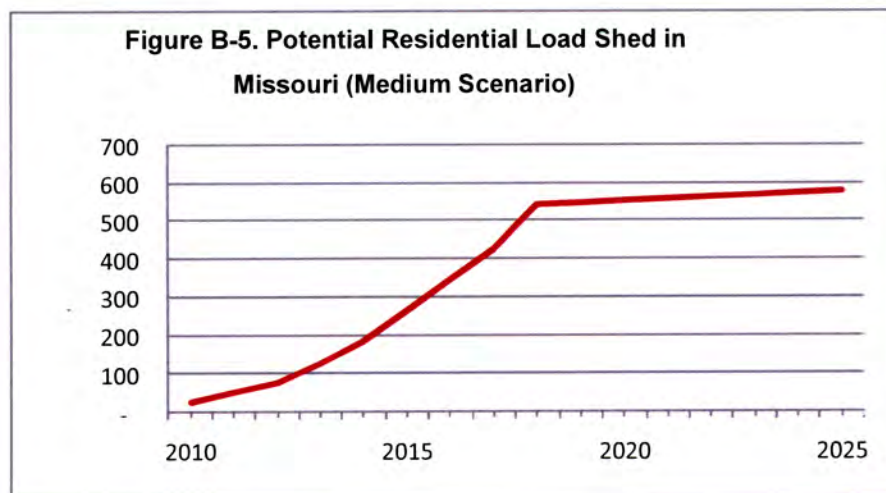
Results

Table B-4 displays the input data and results. In summary, the results for residential programs reveal that a medium scenario reduction of 262 MW is possible by 2015 (with 157 MW possible by the low scenario, and 367 MW by the high). By 2020, 553 MW is achievable through the medium scenario (with 332 MW possible by the low scenario, and 774 MW by the high).

⁵⁵ Programs where participants are included in a program unless they chose to "opt-out" experience much higher participation rates. One utility is proposing a "hybrid" program for new construction, where existing customers must opt-in and new construction customers must opt-out. This program assumes that 70% of new construction customers will enroll in the initial years, and 80% in later years (Summit Blue, 2008b).

Table B-4. Potential Load Reduction from AC-DLC In Missouri Residential Homes, in Years 2015 and 2020		
INPUTS	2015	2020
Residential Peak Demand (MW)	9,717	10,040
Residential Customers (in thousands): ^a Total	2,813	2,966
Single Family	2,055	2,153
Multi-Family	559	596
Eligible Residential Customers: Single Family ^b	87%	
Eligible Residential Customers: Multi-Family ^b	89%	
Load Reduction per AC-DLC per Single-Family Unit (kW)	1.0	
Load Reduction per AC-DLC per Multi-Family Unit (kW)	0.6	
DR Participation Rates of Eligible Customers:		
Low Scenario	25%	
Medium Scenario	25%	
High Scenario ^c	35%	
RESULTS	2015	2020
Residential Potential DR Load Reduction (MW):		
Low Scenario	157	332
Medium Scenario	262	553
High Scenario	367	774
Notes:		
a. Residential customers reflect number of housing units, as reported from Economy.com.		
b. Analysis assumes residences with central AC are eligible. Residential accounts without central AC are assumed to have no participation. Central AC percents obtained from Ameren 2010 and RLW 2006.		
c. Higher participation than applied in the High Scenario is possible through design of program features, such as "opt-out" participation where participants are included in a program unless they chose to "opt-out".		

Figure B-5 shows the resulting residential load shed reductions possible for Missouri, from year 2010, when load reductions are expected to begin, through year 2025.



Room Air Conditioners

Other DR residential programs could involve tapping into the potential for callable load reductions from room air conditioners. At least one prominent DR provider is exploring the possibility of having manufacturers of room AC units embedding a home-area-network communication device into new units. This would enable cycling of room air conditioners without the need to install radio frequency load switches commonly used for residential direct load control applications. Callable load reductions from room air conditioners would provide a significant boost to load control capability and these reductions would be dispatchable in less than ten minutes. Some utilities are projecting to add a large number of new room air conditioners in the next five to ten years. The additional participation of a fraction of these room AC units could provide a substantial increase to the AC DLC program.

Other Appliances

Based on the experiences of other utilities, expanding the equipment controlled to other equipment beyond AC units can produce additional kW reductions. This could include electric hot water heaters and pool pumps. However, the saturation of electric hot water heaters is lower than for air conditioning, and control of hot water heaters generally produces only about one-third the load impact of air conditioners, especially in the summer when Missouri utilities would most likely be calling DR events.

Commercial and Industrial DR Potential in Missouri

Appropriate commercial sector DR programs will vary according to customer size and the type of facility. Direct load control of space conditioner equipment is a primary DR strategy intended for small commercial customers (e.g., under 100 kW peak load), although TOU rates combined with promising new thermal energy storage technologies could prove an effective combination. Mid-to-large commercial customers and smaller industrial customers could best be targeted for a curtailable load program requiring several hours of advanced notification or, where practical, for an Auto-DR program that can deliver load reductions with no more than ten minutes of advance notice. Thermal energy storage and other scheduled load control programs may also be applicable for some larger buildings or water pumping customers. In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts. These pricing programs are discussed in the above section on "DR for Residential Customers." However, for the purposes of this assessment, a focus on these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

The following DR program descriptions apply to both commercial and industrial customers:

- Small business direct load control (air conditioning)—Small commercial customers (under 100 kW peak load) account for a majority of customer accounts but typically only about one-quarter of total commercial load. Due to the nature of small businesses, particularly their small staffs for which energy management is a relatively low priority, it is not practical to rely on active customer response to load control events. Thus, small businesses may best be viewed in the same way as residential customers for purposes of DR.
- Curtailable load program—This program would be applicable to commercial and industrial customers willing to commit to self-activated load reductions of a minimum of perhaps 50 kW in response to a notice and request from a utility. The minimum curtailment threshold is designed to improve program cost-effectiveness by ensuring that recruitment and technical assistance costs are used for customers who can deliver significant load reductions. Advanced notice requirements would likely be two hours— long enough to allow customers an opportunity to prepare but short enough to maintain the DR resource as a viable resource that can be dispatched by operations staff. Enabling technologies would vary greatly, but

utilities would educate customers about alternatives and could work with equipment vendors to facilitate equipment acquisition and installation. Incentives would be paid as capacity payment (in \$/kW-month) or a discount on the customers' demand charges. Utilities could also offer a voluntary version of the program to attract greater participation. Customers would not commit to load reductions, but incentives would be lower and would be paid only on the reductions achieved during curtailment events.

- **Automated demand response (auto-DR)**—Auto-DR enables customers with automated load control systems to participate in DR events without manual intervention. The advantages of this program include flexibility and ease-of-use by allowing customers to pre-select a level of participation and then automatically take part in a DR event. This program would be marketed to facilities such as high-rise office buildings and large retail businesses that have energy management and control systems (EMCS) that monitor and control HVAC systems, lighting, and other building functions. The benefits of auto-DR over curtailable load programs include customer loads curtailments with as little as ten minutes' notice and greater assurance that customers will reduce loads by at least their contracted amount. Incentives would be paid as either capacity payments or demand charge discounts, but would be greater than for curtailable load program participants due to the additional technology investment that may be required and the allowance of curtailments on relatively short notice. Utilities would offer extensive technical assistance in setting up auto-DR capability and would potentially provide financial assistance as well for customers making long-term commitments.
- **Scheduled load control programs (including thermal energy storage)**—Scheduled load control can help reduce utility peak demand, especially through shifting of space cooling loads enabled by thermal energy storage technologies. Large-customer TES systems could be promoted along with customer commitments to reduce operation of chillers or rooftop air conditioners during specified peak hours. Customers' return on investment can be increased by encouraging migration to a TOU rate, which would offer a rate discount for many of the hours that TES systems are recharging cooling capacity. Water pumping systems are typically good candidates for scheduled load control programs and utilities can investigate opportunities in the municipal water supply and irrigation sectors. Other, less traditional, opportunities may also be available, such as the leisure/resort industry's limiting recharging of electric golf carts to off-peak hours.
- **Emergency under-frequency relay (program add-on)**—Under-frequency relays (UFRs) automatically shut off electrical circuits in response to the circuits exceeding pre-set voltage thresholds specified by the utility. Use of UFRs is a valuable addition to a DR portfolio because the load response is both automatic and virtually instantaneous. UFRs can best be integrated into another DR program where participants are already engaging in load curtailment activities. It is expected that some customers who might consider participating in a DR program will not be willing to allow loads to be controlled via UFR since they would not receive any advanced notice. Incentives would also need to be greater to attract participants and provide acceptable compensation. However, the benefits of UFRs warrant their consideration as part of a utility's proposed DR portfolio.

Commercial DR Potential

To estimate potential load reductions for commercial units, a straight-forward approach of applying load shed participation rates and curtailment rates directly to commercial peak demand.

First, assumptions were made on the percentage of commercial customers who are willing to participate in DR programs. One study applied commercial participation rates ranging from 11% to 48% for commercial customers (Summit Blue 2008a). Table B-5 displays participation rates for various types of commercial customers, disaggregated into two different peak demand categories (<300kW and >300kW).

Table B-5. Examples of Commercial Load Shed Participation Rates		
	Peak Category	
Customer Segment	<300kW	>300kW
Office Buildings	11–15%	45–48%
Hospitals	13%	48%
Hotels	14%	45%
Educational Facilities	13%	43%
Retail	11%	42%
Supermarkets	12%	33%
Restaurants	11%	39%
Other Government Facilities	15%	44%
Entertainment	13%	41%
Source: Summit Blue 2008a		

Because facility-specific data was not available for Missouri, three conservative scenarios for participation rates were applied. A medium-scenario load participation rate of 20% was applied as it appears to be an average participation rate found by utilities with DR programs in place. A low scenario of 10% and a high scenario of 30% are applied.

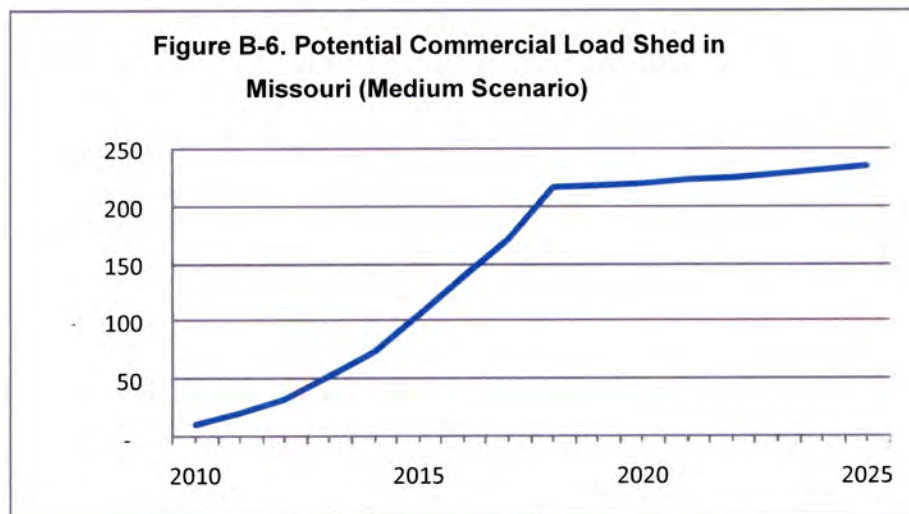
Then, assumptions were made for curtailment rates, based on existing estimates of the fraction of load that has been shed by commercial customers enrolled in event-based DR programs callable by the utility. Table B-6 displays curtailment rates for various types of commercial customers, which range from 13% to 43%. For the purposes of this analysis, 3 conservative scenarios were applied: a low curtailment rate of 15%, a medium curtailment rate of 20%, and a high rate of 25%.

Table B-6. Examples of Commercial Curtailment Rates	
Customer Segment	Average Curtailment Rate
Office Buildings	21%
Hospitals	18%
Hotels	15%
Educational Facilities	22%
Retail	18%
Supermarkets	13%
Restaurants	17%
Other Government Facilities	38%
Entertainment	43%
Source: Summit Blue 2008a	

Table B-7 displays the input data and results. In summary, the commercial sector results reveal that a medium scenario reduction of 106 MW is possible by 2015 (with 40 MW possible by the low scenario, and 198 MW by the high). By 2020, 220 MW is achievable through the medium scenario (with 83 MW possible by the low scenario, and 413 MW by the high).

Table B-7. Potential Commercial Load Shed in Missouri, in Years 2015 and 2020		
INPUTS	2015	2020
Commercial Peak Demand (MW)	5,287	5,505
Load Shed Participation Rates:		
Low	10%	
Medium	20%	
High	30%	
Curtailment Rates:		
Low	15%	
Medium	20%	
High	25%	
RESULTS	2015	2020
Commercial DR load reductions (MW):		
Low	40	83
Medium	106	220
High	198	413

Figure B-6 shows the resulting commercial load shed reductions possible for Missouri, from year 2010, when load reductions are expected to begin, through year 2025.



DR programs that move towards the auto-DR concept can typically provide some load sheds that only require ten-minute notification or less. While some customer surveys have shown that most customers would prefer longer notification periods, many of these customers have not put in place the technologies to automate DR both load shed within a facility and the startup of emergency generation (ConEd 2008). The value of DR and the design of DR programs should take into account system operations. Ten-minute notice DR can be valuable in helping defer some investment in T&D. While not all customers may choose to provide ten-minute notice response, there should be an increasing number of customers that will provide this type of response in the future and programs should be designed to acquire this resource. This type of DR is often a more valuable form of DR with higher savings for the utility, and utilities are often ready to pay up to twice as much to customers for this short-notice responsiveness.

Industrial DR Potential

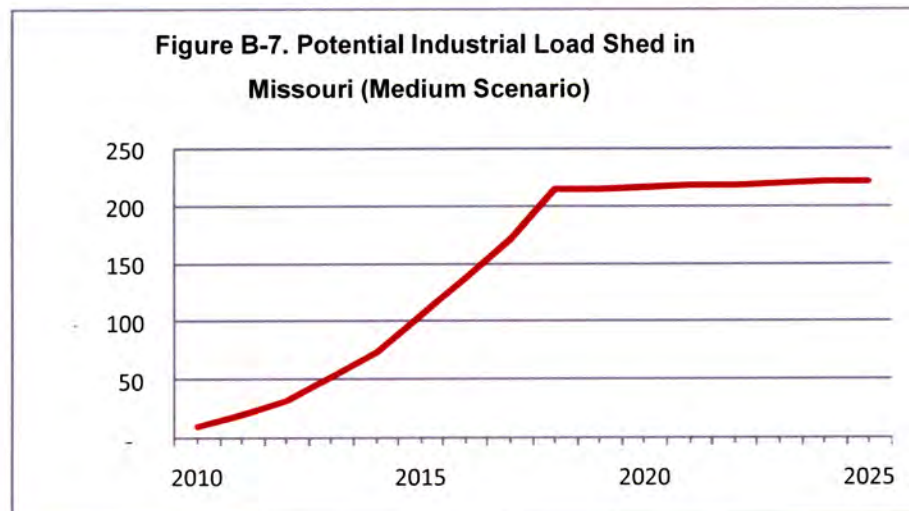
A similar analysis was conducted for the industrial sector: load shed participation rates and curtailment rates were applied to industrial peak demand. A previous study found industrial participation rates to vary from 25% for facilities <300kW, to 50% for >300kW (Summit Blue 2008a). For this study, the following rates were applied to participation: Low (20%); Medium (30%); and High (40%).

Previous studies have found industrial curtailment rates to vary from 17% (Quantec 2007), to 30% (Consortium 2004), to 75% (Nordham 2007), resulting in a mean of 41%. The following conservative rates were applied to curtailment for this study: Low (20%); Medium (30%); and High (40%). With these participation rates and potential load curtailments, the high load reduction potential for the overall industrial sector loads is 16% (i.e., 40% participation and 40% of that load participating).

Table B-8 displays the input data and results. In summary, the industrial sector results reveal that a medium scenario reduction of 106 MW is possible by 2015 (with 47 MW possible by the low scenario, and 188 MW by the high). By 2020, 216 MW is achievable through the medium scenario (with 96 MW possible by the low scenario, and 384 MW by the high).

Table B-8. Potential Industrial Load Shed in Missouri, in Years 2015 and 2020		
INPUTS	2015	2020
Industrial Peak Demand (MW)	2,354	2,403
Load Participation Rates:		
Low	20%	
Medium	30%	
High	40%	
Curtailment Rates:		
Low	20%	
Medium	30%	
High	40%	
RESULTS	2015	2020
Industrial DR load reductions (MW):		
Low	47	96
Medium	106	216
High	188	384

Figure B-7 shows the resulting industrial load shed reductions possible for Missouri, from year 2010, when load reductions are expected to begin, through year 2025.



The largest load reductions, and often the most cost-effective, may be found in Missouri's largest commercial and industrial customers. Data concerning these largest facilities were not available in Missouri so estimates are not quantified separately from the industrial analysis given in the previous section.

It is a topic of concern how the economic downturn could potentially affect DR, particularly in the commercial and industrial sectors. Industry communications reveal that DR efforts have not slowed down with the economy. Many utilities are supporting DR programs, even if capacity is not a current driver. Progress Energy is continuing ahead with their DR programs and recently received approval for their C&I DR program (see section above on "Assessment of Utility DR Activities").

Commercial and Industrial Backup Generation Potential

Emergency backup generation is a prominent component of a callable load program strategy. Some of the emergency generators not currently participating in DR programs may not be permitted for use as a DR resource and regulations may further limit the availability of emergency generation for DR. In some cases, backup generators may not be equipped with the start-up equipment to allow the generator to participate in short-term notification programs. Utilities could consider a program to assist customers with equipment specification and set-up to promote DR program participation by backup generators.

In some instances, there may be environmental restrictions on emergency generation. Emissions of emergency generation may be regulated, and the future of such regulations may add some uncertainty. However, some areas have been able to have such restrictions lifted during system emergencies.

Two approaches can increase the amount of emergency generation in DR programs: 1) facilitating customer-owned generation, and 2) utility ownership of the generation, which is used to provide additional reliability for customers willing to locate the equipment at their facilities.

Customer-Owned Emergency Generation

To increase customer-owned emergency generation, utilities may assist customers with ownership of grid-synchronized emergency generation. Utilities may offer to pay for all equipment necessary for parallel interconnection with the utility grid, as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from a utility's control center, and they can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption.

Utility-owned Emergency Generation

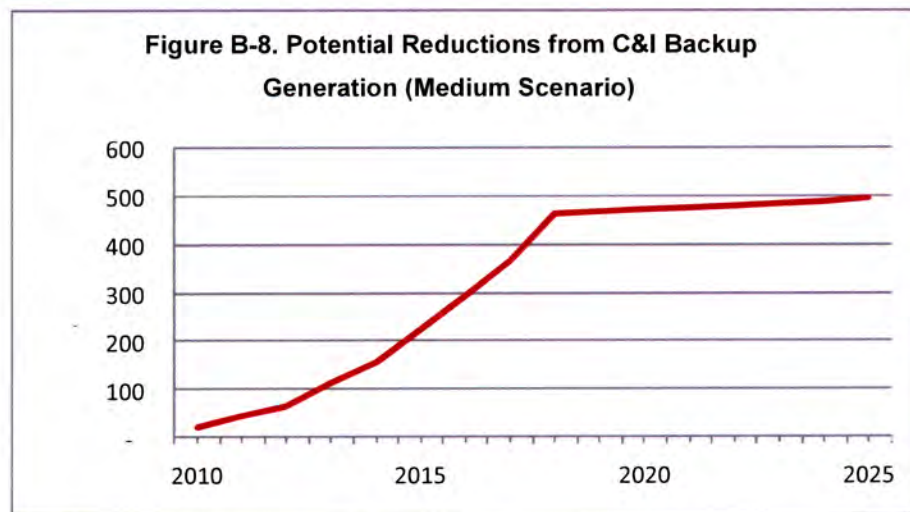
A second approach to increasing the availability of emergency generation for DR is by locating generation at customer sites that can be owned by a utility. Through this type of program, the customer receives emergency generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs. Participants would likely receive capacity payments (\$/kW-month) and/or energy payments (\$/kWh) in exchange for granting a utility to dispatch the units for a limited number of events and total hours per year.

Backup Generation in Missouri

Total Missouri back-up generation capacity for 2015 is estimated at approximately 1,123 MW.⁵⁶ Additional analysis revealed that the commercial and industrial back-up capacity, each, is approximately half of the total capacity, at just over 563 MW.⁵⁷ Assuming a medium scenario that 40% of the total backup in Missouri is available for load shed, then 225 MW of backup generation is available by 2015 and 469 MW is available by 2020 (see Table B-9).

Table B-9. Potential Reductions from C&I Backup Generation in Missouri, in Years 2015 and 2020a		
INPUTS	2015	2020
Total Backup Generation Capacity (MW)	1,123	1,173
Backup Generation Potential (%):		
Low	30%	
Medium	40%	
High	50%	
RESULTS	2015	2020
Potential Reduction from C&I Backup Generation (MW):		
Low	169	352
Medium	225	469
High	282	587

Figure B-8 shows the resulting commercial and industrial backup generation reductions possible for Missouri, from year 2010, when load reductions are expected to begin, through year 2025.



Pricing and Rates

In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs callable by the utility. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts; however, for the purposes of this assessment, a focus on these load response programs

⁵⁶ Back-up generation capacity in Missouri was estimated from form EIA-861 filings submitted by utilities nationwide (EIA 2007). However, only utilities providing approximately one-quarter of total kWh report these numbers. It was assumed that the prevalence and usage of distributed generation in the remaining 75% of utilities is similar.

⁵⁷ The analysis first determined the back-up generator population nation-wide, and then scaled the data down to the Midwest region (CBECS resolution), accounting for proportional differences in building stock nation-wide and region-wide. The region-wide results were then scaled down to Missouri specifically using the ratio of Missouri population to regional population.

is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

New rates may be introduced as part of a DR program, and may include real-time prices, or other time-differentiated rates, for commercial and industrial customers, and a modification of any existing residential time-of-use (TOU) rates. Any new rate structures would be designed to reduce system demand during peak periods and provide an opportunity for customers to reduce electric bills through load shifting.

Critical peak pricing (CPP) is a viable option for inclusion in a DR portfolio. In FERC's 2006 survey of utilities offering DR programs (citation below), roughly 25 entities reported offering at least one CPP tariff. However, many of the tariffs were pilot programs only, and almost all of the 11,000 participants were residential customers. The apparent lack of commercial CPP programs is supported by a 2006 survey of pricing and DR programs commissioned by the U.S. EPA (below), which found only four large-customer CPP programs, all of them in California. The pilot programs in California linked the CPP rate with "automated demand response" technologies that provide most of the impact. The CPP rate itself, and the price incentive that it creates, is not the driver behind the load reductions.

As stated, rate pricing options were not analyzed in this analysis. Event-based pricing programs achieve impacts very similar to the callable load programs presented above. Pilot studies and tariff evaluations of TOU-CPP programs⁵⁸ show the load reductions for called events are similar in magnitude to air conditioning DLC programs. This is not surprising in that most TOU-CPP participants use a programmable-automated thermostat to respond to CPP events in a manner similar to a DLC strategy. One difference is that the customer response is less under the control of the program or system operator that could change cycling strategies or thermostat set points across different events or different hours within an event. Similarly, demand-bid programs are simply calls for target load sheds, i.e., those bid into the program.

In general, the direct load shed programs seem to provide greater MW of participation and more reliable reductions. However, the use of either TOU-CPP or a demand-bid program represents a point of view or policy position that price should be a centerpiece of the DR effort and help customers see prices in the electricity markets. From a point of view of simplicity and attaining firm capacity reductions, the direct load shed programs may offer some advantages. Ultimately, the choice between these direct load shed programs and pricing programs may come down to customer preferences and decisions by policy makers on the emphasis of DR efforts.

A time-differentiated rate is another option to consider that may not be "callable." Such rates include day-ahead real-time pricing (RTP), two-part RTP tariffs, and standard TOU rates. Although they are not "callable" in that the rate is generally in effect every day, there may be synergies between time-differentiated rates and callable load programs. In general, an RTP option will result in customers learning how to reduce energy consumption on essentially a daily basis when prices tend to be high (e.g., summer season afternoons and early evenings). Customers do not tend to track exact hourly prices, but they know when prices are likely to be higher (e.g., summer season afternoons with higher prices on hot days).⁵⁹ The benefits to the customer come from reducing consumption across many summer days when prices are high, rather than a focus on reduction during system event days. In general, the reductions on system peak days are roughly the same as on any summer day when prices are reasonably high. As a result, an RTP option can provide substantial benefits by increasing overall market and system efficiency through shifting loads from high priced periods to periods with

⁵⁸ See Public Service Electric and Gas Company, "Evaluation of the MyPower Pricing Pilot Program," prepared by Summit Blue Consulting, 2007; and the California Energy Commission, "Impact evaluation of the California Statewide Pricing Pilot—Final Report," March 16, 2005. Web reference: <http://www.energy.ca.gov/demandresponse/documents/index.html#group3>.

⁵⁹ See evaluations of the hourly pricing experiment offered by ComEd and the Chicago Energy Cooperative performed by Summit Blue Consulting (2003 through 2006).

lower prices. However, these tariffs may not provide the needed load relief on system-constrained event days.^{60, 61}

Summary of DR Potential Estimates in Missouri

Table B-10 shows the resulting load shed reductions possible for Missouri, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The recommended, conservative, medium scenario results show a reduction in peak demand of 699 MW is possible by 2015 (4.0% of peak demand); 1,458 MW is possible by 2020 (8.1% of peak demand); and 1,530 MW is possible by 2025 (8.1% of peak demand).

Table B-10. Resulting Load Shed Reductions Possible for Missouri

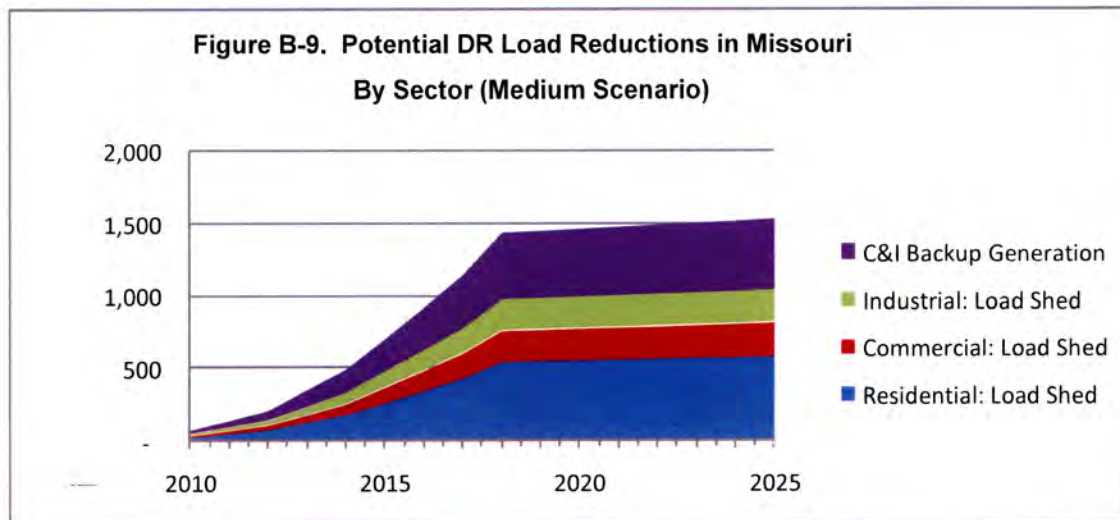
	Medium Scenario *Recommended Scenario		
	2015	2020	2025
Residential	262	553	580
Commercial	106	220	234
Industrial	106	216	222
C&I Backup Generation (MW)	225	469	494
Total DR Potential (MW)	699	1,458	1,530
DR Potential as % of Total Peak Demand	4.0%	8.1%	8.1%

The high scenario DR load potential reduction is 2,158 MW or 12.0%. This is within a range of reasonable outcomes in that it has a ten year rollout period (beginning of 2012 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value near the high scenario would make a good MW target for a set of DR activities. However, for the purposes of this study, we state the Medium Scenario as a realistic potential estimate of load reductions from DR programs.

Figure B-9 shows the resulting load shed reductions possible for Missouri, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

⁶⁰ One way to make an RTP tariff more like an event-based DR program is to overlay a critical peak pricing (CPP) component on the RTP tariff where unusually high prices would be posted to customers with some notification period. Otherwise, it is unlikely that the high levels of reduction needed for system-event days would be attained.

⁶¹ The complementarity of event-based load shed programs with RTP tariffs is assessed in: Violette, D., R. Freeman, and C. Neil. DR Valuation and Market Analysis—Volume II: Assessing the DR Benefits and Costs, Prepared for the International Energy Agency, TASK XIII, Demand-Side Programme, Demand Response Resources, January 6, 2006. Updated results are presented in: Violette, D. and R. Freeman; "Integrating Demand Side Resource Evaluations in Resource Planning," Proceedings of the International Energy Program Evaluation Conference (IEPEC), Chicago, August 2007 (also at www.IEPEC.com).



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates include assumptions based on utility experience regarding growth rates, participation rates, and program design, among others, and will adjust accordingly if differing assumptions are made. The assumptions made are believed to be conservative, and reflect minimum achievable DR potential. For example, participation rates for all of the sectors are based on experience in other states, and are based primarily on customer awareness, the ability to have automated response, and the adequacy of reward. If the statewide education program now required in Missouri promotes DR programs and adequate incentives are offered, then participation rates higher than the medium scenario are entirely realistic.

Comparison of Estimated DR Potential with Results from Other Studies

These estimated reductions in peak demand are within a range to be expected for a population of Missouri's size. Estimates of DR in other states show that the estimates calculated here for Missouri are reasonable: 15% reductions in peak demand in Florida are possible by 2023 (Elliott et al. 2007a), and 13% are possible in Texas, also by year 2023 (Elliott et al. 2007b). DR potential for a utility in New York was estimated to be 9.3% of peak demand in 2017 (Summit Blue 2008a). This finding is similar to that of a recent analysis estimating that peak load reductions from DR nationwide will be 8.2% of system peak load in 2020 and 14% by 2030 (EPRI and EEI 2009). Estimation methods differ among the studies, but nonetheless show that the 8% (medium scenario) and 12% (high scenario) reductions in Missouri are realistic and achievable with institutional and economic commitments.

A FERC Staff Report released in the Summer of 2009 on DR potential concludes that 9% and 14% reductions are feasible in Missouri, from the "Expanded Business as Usual" and "Achievable Potential" scenarios for 2019 (FERC 2009). The KEMA (2011) report also used the FERC models (with slight adjustments made to inputs) and estimated the same reductions.

The FERC analysis includes significant contributions from innovative pricing and rates, and is based on higher participation rates and a quicker rollout, and consequently are higher than those estimated in this report and ramp up more quickly.

As stated in the "Pricing and Rates" section of this report, the DR potential estimates focus on the use of direct load control and curtailable load response programs callable by the utility. This focus is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency. Whereas the FERC estimates gain most benefits from pricing programs, this report did not examine aggressive pricing scenarios or complete restructuring of rates (covering all customers) where prices would be

responsive to market effects and have considerable impact on peak demand. This report examined cases involving 10%–40% of customer load participating in DR programs. Newer visions for pricing options enabled by a smart grid infrastructure have larger numbers of customers facing real-time market pricing, resulting in greater decrease in peak demand. The FERC report's "Achievable Potential" is realized if all customers have dynamic pricing tariffs as their default tariff and 60–75% of customers adopt this default tariff. Therefore, the estimates derived in the FERC study give further support that the results from this report are reasonable and achievable through traditional DR programs.

Recommendations

This assessment indicates that the system peak demand can be reduced by approximately 8.1% or 1,458 MW in 2020 in the medium case and 12.0% or 2,158 MW in the high case. The medium scenario is the recommended scenario and even the high case is considered to be within a reasonable range if aggressive action begins by the end of 2011, providing for a ten-year rollout of the DR efforts (at the beginning of 2012 through the end of 2020).

Key recommendations for increasing load reductions from DR programs include:

- Research should continue (as initiated by the Commission) to determine if any Missouri statute, law, or regulation are prohibiting or restricting electric utility customers from participating directly or indirectly through aggregator of retail customers (ARCs) in DR bidding programs and other issues concerning implementation of DR.
- Appropriate financial incentives need to be offered for programs administered directly by the utilities or for outsourcing DR efforts to aggregators. Research should also be conducted to determine the optimal relationship between Missouri customers, utilities and ARCS in regards to DR participation.
- Missouri has some history of time-differentiated rates. Pricing should form the cornerstone of an efficient electric market. Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.
- DR programs need to be integrated with the delivery of EE programs for greatest impact and efficiencies. Gains in delivery efficiency are possible by combining and cross-marketing EE and DR programs. These can include new building codes and standards that include not only energy efficiency construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.
- Key programs that should be offered by Missouri energy providers which can be designed within a 12-month period include:

- Residential and small business AC direct load control using switches or thermostats (or giving customers their choice of technology).
 - Auto-DR programs providing direct load curtailment for larger commercial and industrial customers.
 - Callable interruptible programs with manual response to an event notification for larger commercial and industrial customers where auto-DR approaches are not acceptable to the customer or technically not feasible.
 - Aggressive enrollment of back-up generators in DR programs.
- Load reduction programs typically have less need for pilot programs as the reductions are defined by the equipment and processes outlined by the program for each participant. Time differentiated pricing is a cornerstone of efficient electric markets and the design of these programs may need more pilot testing as the customer response to pricing is voluntary and not set (as often) by program design.
 - Plan for at-scale programs through the rollout period. Pilot programs can be important in determining the appropriate design of cost-effective DR programs. However, there are established DR programs and technologies. Even with the unique circumstances in Missouri, these programs can be designed for deployment at scale. However, this approach recognizes that the first year of program deployment and possibly the second year should be designed to test key design components as part of a program shakeout. The third year of a program that should represent an efficient design and an at-scale program. DSM programs are designed to be flexible and undergo year-to-year changes due to market, customer and technology factors. This will always be the case and the benefits of discrete pilot program can limit overall program participation for a number of years resulting in “lost DR MWs.” The politics of DSM and diverse positions of parties can result in a compromise in the implementation of programs leading to a two to three-year pilot program. This can delay the delivery of DR at scale resulting in higher overall costs. The over-use of pilots that do not acknowledge the ability of a program roll-out to have at-scale deliver as its goal in year three, but to also have tests of design components and decision nodes built into the first two year of program rollout can result in “death by piloting” for attainable DR MWs. Also, a decision to run a pilot program must be based on the assumption that the program will not have enough flexibility in design and on-going decision nodes during the first two years to allow for the ramp up into full scale efficient deployment in year three.
 - Customer education should also be included in DR efforts in Missouri. There is some perceived lack of customer awareness of programs and incentives were programs do exist. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers’ role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight.

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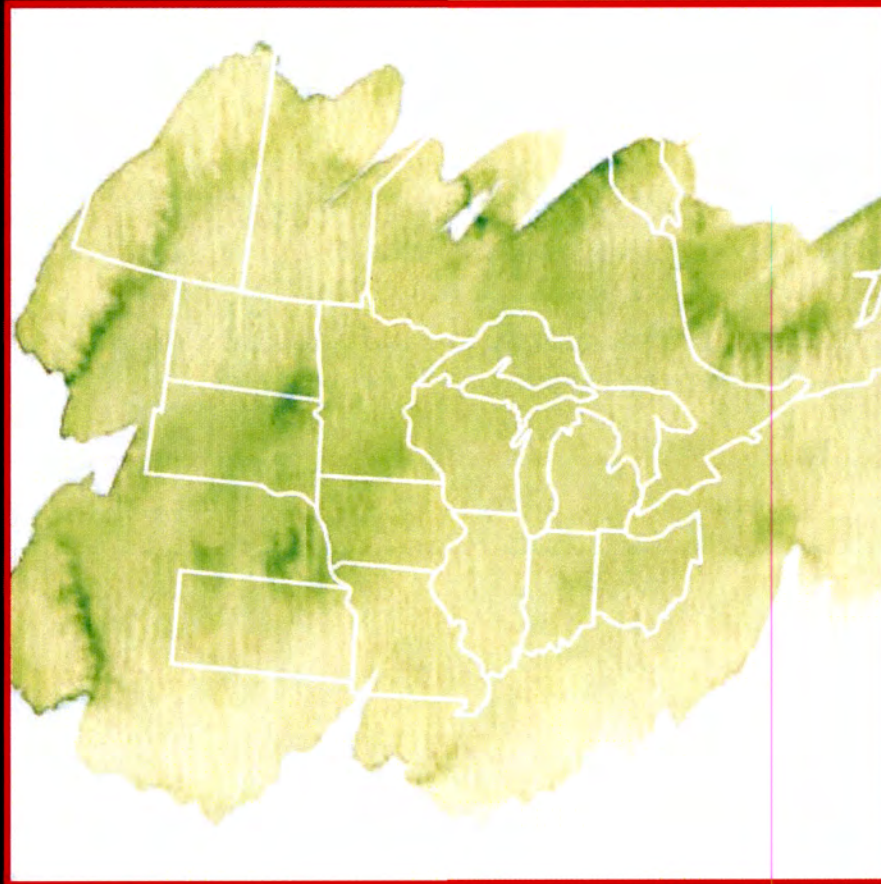
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A REVIEW AND ANALYSIS
OF EXISTING STUDIES OF THE

ENERGY EFFICIENCY RESOURCE POTENTIAL IN THE MIDWEST



A POLICY WHITE PAPER IN SUPPORT OF THE
MIDWESTERN GOVERNORS ASSOCIATION
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AUGUST 2009

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Executive Summary

Energy efficiency improvements have the potential to slow the growth of electricity and natural gas use and reduce utility greenhouse gas emissions in the Midwest. Currently, the best programs in the region (Iowa, Minnesota and Wisconsin) are capturing savings from energy efficiency of 0.7 percent of annual retail energy sales. Raising that level of savings to two percent of annual retail sales of natural gas and electricity is a bold, aggressive and challenging goal that would put the Midwest in a leadership position in addressing climate change. Achieving such an aggressive target would not be unprecedented, however, as Efficiency Vermont recently reported that it achieved savings of 2.5 percent in 2008.¹

The Energy Security and Climate Stewardship Platform endorsed by the governors of Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota and Wisconsin and the premier of Manitoba in 2007 acknowledged the value of energy efficiency and set the goal of meeting two percent of the Midwest's annual retail sales of natural gas and electricity through energy efficiency improvements by 2015. Recognizing that this goal is substantially greater than current policies and programs are achieving, the Energy Efficiency Advisory Group of the Midwestern Governors Association initiated a study to collect, catalog and analyze information about the achievable potential of energy efficiency in the region. The intent of this analysis is to report the results of those studies, and to contrast them with the preliminary stated goal of achieving two percent annual savings. These prior studies describe past practices and therefore should not be interpreted as limiting future

achievements. *The key question under review here is not whether we should strive to replicate typical historical results and estimates, but whether we can exceed them and by how much.*

Studies identifying energy efficiency potential were a staple of utility integrated resource planning and demand-side management activities in the 1980s and early 1990s. These studies were used to identify energy efficiency opportunities and screen the applicable technologies for cost effectiveness in order to develop programs and budgets for utility-delivered conservation efforts. As utilities restructured in the mid- to late-1990s, they relied more on competitive market forces to direct their resource investments and the energy efficiency potential study fell by the wayside. However, with growing concerns over climate change and greenhouse gas emissions, energy efficiency has reemerged as a viable utility resource and potential studies are again being conducted to identify energy efficiency opportunities. We identified ten studies conducted in the Midwest since 2001 to estimate the potential for energy efficiency to meet a portion of the energy need.

The Energy Center of Wisconsin and the American Council for an Energy-Efficient Economy undertook a review and analysis of these recent energy efficiency potential studies conducted in the Midwest to help explain the gap between existing efforts and new initiatives and to determine how realistic the annual two percent savings goal is. The studies identify ranges of savings from energy efficiency potential of 0.5 to 1.6 percent per year. These are clearly lower rates of savings than called for in the Energy Security and Climate

¹ Efficiency Vermont, Year 2008 Preliminary Savings Claim, March 23, 2009.

Stewardship Platform. However, because of a number of disparities among the studies and the lack of consistent assumptions, we conducted further analysis to understand how these differences affected the results and to determine the conditions under which greater efficiency savings potential might be identified.

DISPARITY AMONG THE MIDWEST STUDIES

We found several reasons for the differences in results among the studies we reviewed: (1) the studies varied in terms of which types of potential were being determined; (2) the studies were not consistent in which sectors were included (residential, commercial and industrial); and (3) the vintage of the data used to determine energy savings varied considerably. Some of the data used to determine energy efficiency potential is 20 years old. More recent data is difficult to obtain.

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The most important of these differences lies in the first category. There are three perspectives commonly used to determine energy efficiency potential. They are technical, economic and achievable. Technical potential estimates the energy savings from replacing existing technologies with more energy-efficient technologies regardless of cost or practicality. Economic potential is a subset of technical potential in which a cost-effectiveness criterion is used to screen out technologies whose benefit (energy cost savings) is less than the cost to purchase, install and operate. Finally, achievable potential is a subset of economic potential. It considers practical realities that inhibit markets from delivering efficiency savings. These include budget constraints and lack of information. Achievable potential is the most direct estimate of the impacts that policies and programs can have on influencing customer energy use. Among the studies we reviewed some estimated both economic and achievable potential while others estimated only one or the other.

ADDITIONAL STUDIES

As a result of all these differences there were not enough common data points from the Midwest studies to draw robust conclusions from them. In order to get a more comprehensive picture of what these studies reveal about the potential for energy efficiency savings, we drew on a larger set of studies from throughout the United States and Canada. While these studies also varied in scope, we were able to draw some conclusions from this broader sample. Nine out of the 20 non-Midwestern studies identified either achievable or economic potential of 1.9 percent per year or above. Even though these studies produced higher estimates of potential than those produced for Midwest states, our analysis of how these studies were conducted suggests that they were designed with what David Goldstein refers to as a standard conservative bias, one that underestimates the amount of achievable energy efficiency.

Many studies have looked at the cost effective potential for efficiency by examining the supply curves for saved energy in detail for major end uses. Yet virtually all of these studies rely on methodologies that are excessively conservative if the goal of policymakers is to meet aggressive climate change emissions reduction goals. (Goldstein 2008)

Yet, despite underestimating achievable energy efficiency potential, almost half of these studies found annual achievable potential of nearly two percent. If we apply a new paradigm in which energy efficiency is an explicit component of a climate change policy and we use innovative approaches to deliver comprehensive programs, we'll find that the Energy Security and Climate Stewardship Platform goal of two percent, while aggressive, is realistic. We must recognize energy efficiency as a least-cost resource in order to align stakeholder interests, provide adequate program funding and remove the barriers that prevent us from achieving these higher levels of energy efficiency.

IDENTIFYING GREATER ENERGY EFFICIENCY SAVINGS POTENTIAL

Achievable potential, as explained previously, is a subset of both technical and economic potential. The focus for achievable potential, however, is on the impact that policies or programs have on reducing energy use. In this context, the overarching policy goal stated in the Energy Security and Climate Stewardship Platform is to reduce CO₂ and other greenhouse gas emissions. This context is different than any of our previous experience with energy efficiency funding and goal setting, and has not driven estimates of achievable energy efficiency potential in the past. This suggests that we should expect to see upward revision in energy efficiency potential estimates in future studies.

Our analysis suggests that designing a study of energy efficiency potential that accounts for the policy goal of reducing CO₂ and other greenhouse gas emissions and that eliminates the conservative biases of earlier studies will result in annual savings potential of two percent or higher. More importantly, recent experience shows us the potential for energy efficiency and conservation to significantly reduce our energy use. In 2000–2001 California responded to its electric reliability crisis by enacting an unprecedented level of energy efficiency and conservation programs supported by a broad public information campaign. The results were dramatic—6.7 percent reduction in total electricity use in 2001. While this effort was in reaction to a crisis, it clearly indicates that energy efficiency and conservation programs can achieve high levels of savings. Achievable energy efficiency, then, is clearly a function of financial investment, programmatic efforts, public outreach and political will.

CONCLUSIONS

In this era of heightened concern over climate change and looming legislation regulating carbon emissions, aggressive goals for energy efficiency and conservation are appropriate components of Midwestern energy policy. Estimates of achievable energy efficiency potential derived from studies done in the past do not reflect the different social, political and economic contexts that exist today and should not be relied on to define or limit current program efforts.

Policy initiatives to address climate change provide the impetus to change the paradigm for determining achievable energy efficiency savings. When we consider the cost of carbon, the cost to build low-carbon generating plants or develop renewable resources to meet growing electrical demand, then greater investment in energy efficiency captures more savings while remaining both cost effective and less costly than the alternatives.

The Midwest is well positioned to raise its overall energy efficiency efforts. Several Midwestern states have mature, long-running utility or state-wide public benefit energy efficiency programs in place. These programs, when combined with new initiatives, more timely adoption of codes and standards, use of combined heat and power as a source of industrial efficiency, and governments leading by example will serve the region well in achieving the efficiency goals of the Energy Security and Climate Stewardship Platform.

Introduction

The Energy Efficiency Advisory Group (EEAG) of the Midwestern Governors Association (MGA) collaborated with the Energy Center of Wisconsin and the American Council for an Energy-Efficient Economy to determine whether there is data to support the aggressive goal of two percent reduction in annual energy use from energy efficiency strategies endorsed in the Energy Security and Climate Stewardship Platform. To accomplish this task, we reviewed and analyzed recent studies estimating the potential for energy efficiency to reduce energy use. We reviewed these studies from the policy objectives they were attempting to meet, the methods used to determine the amount of energy efficiency that could be achieved as well as the sectors of the economy they covered. We concluded that:

- The goal of two percent savings per year for the region from a combination of electricity and natural gas is aggressive but supportable. While it may be difficult for an individual state without past experience with energy efficiency programs to meet the two percent goal in the near term, the region as a whole can do it with utility programs, updated codes and standards, combined heat and power and government leading by example. Additionally, it would be difficult to achieve two percent savings for natural gas with utility programs alone, but when we combine electric savings with gas savings from all efforts, the two percent average reduction in total BTUs is achievable.
- The two percent target will stretch state and utility energy efficiency programs. States with strong,

well-established programs are in a better position to reach the higher goals. States restarting programs after long periods without activity have a bigger challenge, but also have large amounts of relatively low-cost and easy-to-achieve energy savings (from commercial lighting, for instance).

- Our energy and economic policy context has changed dramatically making higher investments in energy efficiency cost effective. In a world in which new electrical generation will have to have no or low carbon emissions, energy efficiency is the least costly action because it curtails the growth in electrical energy use and delays the need to build more costly clean power plants.

POLICY OBJECTIVES

Changing policy objectives provide one context for reevaluating the role of energy efficiency. The energy policy landscape has changed dramatically in the past few years as the U.S. attempts to grapple with the problem of climate change. This changing landscape includes:

- Realization that some form of monetizing carbon costs is inevitable.
- Recognition that energy price volatility is increasing.
- Increases in the costs of constructing new power plants.
- Concerns about the ability to finance and secure cost-recovery for large electric generation construction projects.

-
- Shrinking reserve margins and concerns about electric system reliability.
 - Increasing impact of energy costs on all customers in an economic recession.

These are some of the factors that have elevated energy efficiency resources and provide the backdrop for our analysis of existing studies of energy efficiency potential in the Midwest.

Studies of Energy Efficiency Potential

Studies to estimate the potential for energy efficiency improvements and associated energy savings are fundamental to the planning, development, implementation and evaluation of energy efficiency programs provided to energy utility customers. Energy efficiency potential studies examine customer markets and end-use applications for the full spectrum of technologies and products that use energy in our homes, businesses, institutions and industries. These studies seek to identify energy efficiency opportunities and quantify the savings possible through implementation of measures that capture such opportunities. Such studies provide a ready road map showing where program efforts should be directed, as well as help to establish baselines against which to measure improvements in energy efficiency.²

The practice of conducting energy efficiency potential studies is not new. As integrated resource planning and demand-side management arose and were applied in the 1980s and into the 1990s, such studies were commonly performed. Through these studies, utilities and other program administrators identified available energy efficiency opportunities and screened such measures for cost effectiveness to determine what types of programs should be developed and provided to customers. Such studies also were helpful in determining allocation of program budgets across different customer segments and end-use applications (such as lighting, air-conditioning, space heating, motor-drive systems, water heating, and industrial processes). The number of energy efficiency potential studies diminished greatly from the

mid to late 90s into the early 2000s as many utility jurisdictions restructured their markets to introduce competition at the retail level or otherwise relied on greater use of competitive forces within energy markets to direct utility resource investment.

However, changing market conditions and a re-examination of restructuring in many of these same jurisdictions has led to a new wave of interest and policy focus on energy efficiency as a bonafide utility resource—a resource fully valued in development of energy resource portfolios that include both supply and demand resources.

This rise, fall and re-emergence of energy efficiency potential studies seen nation-wide also occurred in the Midwest. *Table 1* identifies the set of studies that we found in our research for recent energy efficiency potential studies.

OVERVIEW OF METHODOLOGIES AND DATA USED IN POTENTIAL STUDIES

The studies that we reviewed share the overall objective of identifying energy efficiency opportunities for selected customer segments. The data and methodologies vary among the studies, but generally use disaggregated market and end-use data on selected energy technologies and applications to create estimates of potential energy savings from implementing more energy-efficient improvements. This is done end-use by end-use to create an aggregate estimate for all selected end-uses in

² These studies, however, do not measure non-utility efficiency efforts such as those included in the Energy Security and Climate Stewardship Platform.

a given study. The quality and availability of such end-use data vary significantly. Data that are used include:

- Appliance and technology saturation surveys
- Sales data
- Housing stock characteristics
- Commercial building stock characteristics
- End-use load profiles (energy use patterns by technologies)
- Historical energy use by type of customer, building and industry

The vintage of these data vary considerably, too. There are certain types of data that are difficult and costly to obtain, such as detailed customer end-use profiles. We have found in our work (York, Kushler and Witte, 2007) that much of the available end-use

load profile data are 10–20 years old. Other data, such as sales data from manufacturers and suppliers, may be difficult to obtain as the information is often proprietary and the companies do not wish to reveal data that competitors may find advantageous.

Often, studies are conducted with proprietary models which may not reflect the policy questions posed by the stakeholder. Such models while effective in cataloging end use opportunities are not generally flexible enough to address a changing landscape with respect to climate change issues. Such models can extend the business-as-usual practices with current technologies, but may fail to take into account how policymakers may encourage the public and utilities to more actively engage in efficiency strategies.

Table 1—Summary of Midwestern Studies Reviewed		
Title	State/ Region	Date Published
Energy Efficiency and Customer-Sited Renewable Energy: Achievable Potential in Wisconsin 2006–2015	WI	2005
Illinois Residential Market Analysis	IL	12–May–03
Assessment of Energy Efficiency Potential: 2006–2025	Ontario	7–Oct–05
Kansas Energy Council DSM Potential Study and Plan	KS	2008
Duke Energy Indiana DSM Market Assessment and DSM Action Plan: Final Report	IN	2007
2006 Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study	MO	15–Nov–06
Assessment of Energy and Capacity Savings Potential in Iowa	IA	Feb–08
Midwest Residential Market Assessment and DSM Potential Study	Midwest	Mar–06
Summary Document for Minnesota Market Assessment Studies	MN	2004
Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin for the Years 2012 and 2018	WI	2009
Energy Efficiency and Demand Response Potential for Iowa Municipal Utilities for the Years 2012 and 2018	IA	2009
Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010–2030)	U.S.	Aug–08
Minnesota Gas Energy Efficiency Potential	MN	2009

There are three perspectives commonly used in defining different energy efficiency potentials:

- Technical
- Economic
- Achievable

Technical potential is an estimate of how much energy savings could be achieved by replacing existing technologies with more energy-efficient technologies without consideration of costs and practicality. Consequently, technical potential typically defines an upper boundary of the potential for energy efficiency.

Applying cost effectiveness as a criterion is used to screen measures according to their costs relative to benefits. If the value of the benefits (usually measured as the value of energy savings and in some cases, additional quantified customer benefits) is greater than the costs for procuring, implementing and operating a given measure, it is determined to be cost-effective. The economic potential is thus a subset of the technical potential.

As a final screen of energy efficiency potential, many studies include an estimate of the achievable energy efficiency potential. This is a subset of the economic potential. The achievable energy efficiency potential is an estimate of the magnitude of energy efficiency improvements that can be made, accounting for practical limits and barriers towards implementing measures that are cost-effective (or economic). This requires estimating how mechanisms used to promote greater energy efficiency can influence customer choices and behavior related to energy use. These mechanisms include utility demand-side management programs, public benefits energy efficiency programs, building codes and appliance standards. Estimating the achievable potential is thus an estimate of the possible impacts that various policies and programs can have on influencing customer energy use through adoption and implementation of more energy-efficient technologies.

To illustrate what these different potentials mean, consider the case of compact fluorescent light bulbs (CFLs) for use by residential customers. The technical potential would estimate the amount of energy savings that could be achieved by replacing all existing incandescent light bulbs and assuming that all future purchases of light bulbs would be CFLs. The economic potential for residential CFLs would add a cost-effectiveness criterion identifying only those applications of CFLs where the benefits are equal to or greater than the costs of replacing incandescent light bulbs. CFLs generally have a greater purchase cost that can be offset—or paid back—by the lifetime energy and cost savings that would accrue. However, not all applications may yield such lifetime savings; typically those applications with limited hours of operation (such as closets or garages). Finally, not all customers will purchase and use CFLs for applications where they are cost-effective. In addition, many customers wait until existing incandescent bulbs burn out before replacing them. Therefore, the achievable potential is an estimate of the energy savings that would result from all those CFLs actually purchased, installed and used by customers through the influence of energy efficiency programs and related policies (such as codes or standards). This requires estimating how many customers will participate in a program or be affected by other policies and the associated number of applications for each customer that would be changed to CFLs.

Installation of CFLs to replace incandescent bulbs is one of many energy efficiency measures included in most energy efficiency potential studies. Clearly the accuracy of the estimates is a direct function of the accuracy of baseline data and of the assumptions used to develop the estimates, such as program participation and end-use profiles (how customers actually use a device and how it performs in a given application).

COMPARING THE STUDIES

Table 2 presents the summary results and comparisons based on our review of the Midwestern energy efficiency potential studies. For this table and our comparisons we focused on just the economic and achievable potentials as these are the most relevant to discussions of establishing policy and program goals since they account for costs, benefits and practical implementation of energy efficiency measures. The values shown in Table 2 show the achievable potential savings on an annual basis, i.e., the energy savings possible each year as a percentage of estimated total annual energy sales.

Please note that the gross discrepancy between the economic potential and achievable potential figures reflects the differences in the constructs more than anything else. *Economic potential has no time dimension.* It assumes that all the cost-effective measures are implemented *immediately*. The achievable potential estimates reflect the fact that energy savings occur over time, and not in one fell swoop. The economic potential estimates, therefore, are of limited usefulness when setting an annual savings target, as is the intent here.

One finding immediately apparent from Table 2 is that the studies vary considerably as to which potential—economic or achievable—is included. Some studies include both estimates; others include only the achievable potential while others include only economic potential. The reasons behind these differences are functions of the objectives of a given study as well as the available resources and scope of the study. In some cases, estimating the economic potential may be required to set the level of funding and associated program activity to capture a certain desired fraction of that potential. In other cases the policy and program questions addressed may be focused on savings achieved for a given level or range of program funding and activity.

Another key difference among the studies is which customer sectors are included—residential, commercial

and industrial. Some studies examined and reported results only for the residential sector. Others estimated only an aggregate—or all sector—total. Some studies included estimates for residential, non-residential (commercial and industrial) and combined sectors.

The differences in which savings potentials are estimated and which sectors are included in the estimates make it difficult to draw strong, robust conclusions about these studies. The number of data points for any given metric (e.g., residential economic potential) is limited—two to four across these studies. Despite these limitations, some observations about the available data can be made. Economic potential savings estimates for all sectors range from 14 percent to 45 percent for the studies for which such values are available (median of 20 percent, mean of 24 percent). Achievable potential savings estimates for all sectors range from 0.4 percent to 1.8 percent for the studies for which such values are available—with a median value of 0.9 percent and mean of 1.0 percent.

Given the limited data set of Midwestern energy efficiency potential studies, we drew upon a much larger set of such studies that ACEEE recently reviewed. As discussed earlier, there has been a relatively recent resurgence in the completion and application of energy efficiency potential studies to guide program, policy and planning decisions within the utility industry. ACEEE (Eldridge et al, 2008) completed a study of about 20 recent (year 2000 or later) energy efficiency potential studies from throughout the United States and Canada. This much larger data set provides a more complete, comprehensive picture of what these studies reveal about the potential savings that could result from increased levels of energy efficiency.

Table 3 (page 14) presents the summary data from ACEEE's review. We excluded the few Midwestern studies that were included in ACEEE's review to avoid redundancy and allow a clearer comparison of Midwestern and non-Midwestern studies. We also

added the potential study prepared by the Electric Power Research Institute (EPRI), which was released after the ACEEE analysis was completed. Like the set

of Midwestern studies, there are gaps and differences across the type of potentials estimated and the sectors included in the studies. For economic potential the

range of annual savings is 13 percent to 30 percent with a mean value of 20 percent. For the achievable potential the range of annual savings is 0.3 percent to 4 percent with a mean value of 1.5 percent. While higher, the absolute magnitude of these values is reasonably comparable—with the achievable potential for the Midwestern studies at about 0.9 percent/year and the non-Midwestern studies at 1.5 percent/year. With this broader set of non-Midwestern studies, though, it is important to look beyond the mean at the range—especially on the high side. Several of the non-Midwestern studies had an achievable potential of 1.90 percent/year or above. Natural gas savings may be smaller due to range of measures available.

To assess how well these estimates compare with actual results achieved by leading programs, we examined recent results of a set of 14 leading states in terms of their levels of funding and reported energy savings for the most recent years data are available, 2006 and 2007. *Table 4* presents these results. The values in the table for the metric, energy efficiency savings as a percentage of total

Table 2—Summary of Midwestern Studies

ELECTRICITY				
State (year completed)	Economic Potential (% total savings)		Achievable Potential (% savings/year)	
	Residential Sectors	All Sectors	Residential Sectors	All Sectors
Illinois (2003)			0.5%	
Indiana (2007)			0.8%	
Iowa, Investor-Owned (2008)	30%	17%		
Iowa, Municipal (2009)		22%	0.8%	1.2%
Kansas (2008)		35%	0.9%	1.1%
Midwest (2006)			0.5%	
Minnesota (2003)	14%			
Wisconsin (2009)		18%	1.0%	1.6%
Wisconsin (2005)				0.8%
Ontario (2005)	20%	20%		0.7%
Median	20%	20%	0.8%	1.1%
NATURAL GAS				
State (year completed)	Economic Potential (% total savings)		Achievable Potential (% savings/year)	
	All sectors		All sectors	
Illinois (2003)			0.6%	
Indiana (2007)			0.6%	
Iowa, Investor-Owned (2006)	27%			
Iowa, Municipal (2009)	21%		1.8%	
Kansas (2008)	45%		1.5%	
Midwest (2006)			1.3%	
Minnesota (2009)*	23%		1.6%	
Wisconsin (2009)	16%		1.0%	
Wisconsin (2005)			0.4%	
Median	23%		1.0%	

*These are the median results for the three utilities studied.

Table 3—Other Energy Efficiency Potential Studies—Summary Findings

Region of Study	Technical	Economic	Years	Achievable
U.S. (2000)	NA	NA	20	1.20%
Massachusetts (RLW 2001)	NA	24%	5	NA
California (Xenergy/EF 2002)	18%	13%	10	1.00%
Southwest (SWEEP 2002)	NA	NA	17	1.90%
New York (NYSERDA/OE 2003)	36%	27%	20	NA
Oregon (2003)	31%	NA	10	NA
Puget (2003)	35%	19%	20	0.60%
Vermont (2003)	NA	NA	10	3.10%
Quebec (Optimal 2004)	NA	NA	8	4.00%
New Jersey (Kema 2004)	23%	17%	16	0.70%
Connecticut (GDS 2004)	24%	13%	10	NA
New England (Optimal 2005)	NA	NA	10	2.30%
Northwest (NW Council 2005)	25%	17%	20	0.60%
Georgia (ICF 2005)	29%	20%	10	0.90%
California (Itron 2006)	21%	17%	13	0.60%
North Carolina (GDS 2006)	33%	20%	10	1.40%
Florida (ACEEE 2007)	NA	25%	15	1.30%
Texas (ACEEE 2007)	NA	30%	15	1.20%
Utah (SWEEP 2007)	NA	NA	15	1.70%
Vermont (GDS 2007)	35%	22%	10	1.90%
EPRI (2009)	NA	NA	22	0.3%
Average	28%	20%	14	1.50%

sales (kWh), in 2006 range from 0.1 percent to 1.2 percent with a mean and median both of 0.7 percent. In 2007 the values range from 0.1 percent to 1.8 percent with a mean and median both of 0.8 percent. Vermont has achieved the highest savings as measured by this metric—at 1.8 percent in 2007, up from 1.1 percent in 2006. Connecticut and Rhode Island are two other states that have reached savings levels greater than 1 percent/year—at 1.3 percent and 1.2 percent respectively. Other recognized leading states such as Massachusetts, Oregon and California are just

below this threshold at 0.9 percent savings each in 2007. The three leading Midwestern states included in this study and their 2007 savings levels are:

- Iowa: 0.7 percent;
- Minnesota: 0.7 percent; and
- Wisconsin: 0.7 percent.

A key objective of examining these actual program results is to assess what savings levels are possible through energy efficiency programs and related policies. From this set of programs and associated results, it appears that a few leading programs have crossed the milestone threshold of 1 percent savings per year and that a number of programs readily have achieved savings in the 0.5 percent to 1.0 percent range. These leading states vary considerably in the specific structures of their energy efficiency programs (how they are administered and implemented) and in the associated regulatory mechanisms and policies that support greater energy efficiency (program cost recovery, financial incentives for program administrators, decoupling, building codes, appliance standards, etc.).

Based on these data it may be tempting to conclude that these results represent the maximum levels of savings that programs can achieve. Recall that estimates of the achievable potential generally show values in the range of 0.8 percent to 1.5 percent per year. Comparing these estimates to actual results suggests that programs are indeed at or very close to the achievable savings estimated in various energy efficiency potential studies. We do not believe this to be the case, however. We believe that existing studies of energy efficiency potential underestimate what is achievable and that policies and

related programs can yield savings higher than the results shown in our selected set of leading states. Our reasons for this conclusion follow:

CONSERVATIVE BIASES WITH EXISTING STUDIES OF ENERGY EFFICIENCY POTENTIAL

In examining the reasons why energy efficiency potential studies produce conservative results we draw on a recent paper by Goldstein (2008) and our own experiences. Below we highlight and discuss a number of reasons why existing studies underestimate the sav-

ings “achievable” through energy efficiency programs and related policies.

Avoided costs used in existing studies are much lower than present and projected avoided costs. Existing studies used costs that did not incorporate the much higher fuel costs and dramatically higher power plant construction costs that we now face. Such costs have risen much higher than overall indices for the economy as a whole (inflation adjustments used for economic forecasts).

Table 4—Electric Energy Efficiency Program Savings and Spending Data for Leading States

State	EE Spending: Total (includes utility and non-utility public benefit programs)		Total EE spending as % total revenues for all utilities (investor- owned and public power)		EE spending per capita		EE incremental savings—statewide total—EIA plus non- utility data (or other data source)		EE incremental savings—statewide as % of total state kWh sales	
	\$000s		%		\$/capita		MWh		%	
	2006	2007	2006	2007	2006	2007	2006	2007	2006	2007
Rhode Island	\$17,178	\$17,400	1.6%	1.6%	\$16.18	16.23	96,048	64,995	1.2%	0.8%
Connecticut	\$70,999	\$98,230	1.5%	2.1%	\$20.31	28.05	328,000	355,000	1.2%	1.3%
Vermont	\$15,806	\$23,690	2.4%	3.5%	\$25.46	37.78	62,872	105,243	1.1%	1.8%
Massachusetts	\$125,000	\$120,157	1.5%	1.4%	\$19.43	18.49	455,000	489,622	0.8%	0.9%
Oregon	\$63,318	\$69,107	2.0%	2.2%	\$17.15	18.54	369,827	437,494	0.8%	0.9%
Washington	\$113,288	\$126,678	2.2%	2.4%	\$17.77	19.67	630,691	635,062	0.7%	0.7%
California	\$357,000	\$645,800	1.1%	1.9%	\$9.85	17.64	1,912,000	2,275,000	0.7%	0.9%
Iowa	\$55,296	\$56,293	1.8%	1.8%	\$18.60	\$18.82	315,215	322,177	0.7%	0.7%
Nevada	\$24,000	\$28,700	0.7%	0.8%	\$9.63	11.40	216,000	206,000	0.6%	0.6%
New York	\$224,897	\$241,543	1.0%	1.1%	\$11.61	12.40	823,827	NA	0.6%	NA
Minnesota	\$82,245	\$91,239	1.8%	1.9%	\$15.96	\$17.53	411,999	NA	0.6%	0.7%
Wisconsin	\$77,683	\$80,580	1.4%	1.4%	\$13.94	\$14.32	451,192	467,725	0.5%	0.7%
New Jersey	\$83,177	\$95,914	0.9%	1.0%	\$9.60	10.96	227,764	242,270	0.3%	0.3%
Texas	\$57,800	\$79,500	0.2%	0.2%	\$2.47	3.36	397,305	457,808	0.1%	0.1%
Max									1.2%	1.8%
Min									0.1%	0.1%
Median									0.7%	0.7%
Mean									0.7%	0.8%

Avoided costs used in existing studies do not include a cost of carbon. The cost of carbon could be expressed in several ways. One way is to simply use the traditional avoided cost of conventional generation, but add an estimate of the cost of CO₂ emissions. While there is great uncertainty surrounding carbon-cost estimates, one approximation is the mid-range forecast developed by Synapse Energy Economics, Inc. which predicts a levelized cost of \$30 per ton of CO₂ emitted (\$ 2007). An alternative way to account for the cost of carbon is to base avoided cost on resources with no or low greenhouse gas emissions, e.g. wind generation. A slight deviation on this alternative is to use an avoided cost estimate based on a blend of generation costs determined by a Renewable Portfolio Standard.

Determining an accurate estimate of avoided costs is important because this figure is used as a screen for determining what is cost-effective. Thus, a worthwhile energy efficiency program could be deemed not so simply because out-dated construction costs made it appear not cost-effective. That same worthwhile energy efficiency program may also be erroneously determined not cost-effective when avoided costs are based on the existing Midwestern generation fleet instead of adding incremental generation per a state's Renewable Portfolio Standard.

Existing studies include mostly incremental changes and improvements. Most studies build up the total estimate measure by measure, i.e., estimating the savings possible through individual, independent, incremental measures and then summing up all these savings to yield a total. This type of analysis can miss greater savings possible through integrated, synergistic effects of comprehensive packages of measures. Similarly, existing studies generally look at incremental improvements to existing technologies, not big, bold improvements that may be possible with comprehensive packages of measures and integrated program designs. For example, estimating savings possible for new commercial construction generally will go system

by system, end-use by end-use to yield savings possible through incremental improvements on these individual components and systems in isolation. These studies don't look at the potential for major advances such as zero net energy buildings—a goal now in place in California for all new residential buildings by 2020 and all new commercial buildings by 2030. Studies that only look at marginal improvements to conventional designs and technologies miss the much larger savings that could result from reaching these advanced system goals.

Some markets and end-uses are excluded. Data availability and quality are major determinants of what markets and energy end-uses are included in energy efficiency potential studies. It is not uncommon to exclude a particular market or end-use because of unavailable or poor quality data. In some cases the initial scope of a study may expressly limit the study to certain markets and end-uses of most interest or relevance to the study's sponsor.

Conservatism is built into each key assumption. The amount of data needed to complete energy efficiency potential studies is very large. In many cases the data are best defined by possible ranges of values, especially where there is uncertainty about the values. Most analyses treat the inherent uncertainty of these estimates by using values at the low end of identified ranges of values. Across multiple data sets the net result can be a compounding of conservatism, yielding the most conservative estimates possible. Assumptions about customer participation (realization rates) are particularly biased toward conservative values due to questions about customer acceptance of energy efficiency technologies.

This conservatism is also supported by typical policy and program questions addressed by completing these studies, which generally is to show that present or proposed increases in program spending are adequate to capture a reasonable fraction of the energy efficiency potential.

Existing studies use positive discount rates, which in the context of climate change do not make sense. Discounting the benefits from energy efficiency, as is the convention in typical cost-benefit analyses, runs counter to the rationale for taking action in the face of climate change. If society makes choices (through public policy for example) to mitigate the impacts of climate change, this action reflects a desire to bear costs now, in order that future generations bear less of a cost. In this scenario present value is sacrificed for future value making positive discount rates meaningless, indeed inappropriate. Furthermore, should the impacts of climate change turn out to be on the severe end of the spectrum currently predicted, greenhouse gas emission reduction may actually be more valuable several generations into the future than it is today. Under such circumstances the standard net present value approach simply cannot address these multi-generational issues.

Note that customer discount rates are rarely negative, and in fact we observe very high discount rates used when consumers make energy efficiency decisions. That fact, though, is a manifestation of the problem we are trying to address. Those high personal discount rates, which reflect all the frictions and constraints that market forces cannot overcome, produce much less energy efficiency than is socially optimal. If we were to use private discount rates in energy efficiency potential studies, we would fail to reflect the standard public policy approach to economic analysis, and we would reinforce the *status quo*. Private discount rates do have a key role to play in energy efficiency program design (i.e., they help us identify proper incentive payments), but they typically do not guide the determination of efficiency potential.

Existing studies do not account for emerging technologies, continued improvements of technologies and cost reductions of such technologies over time. Performance and cost data of energy-efficient technologies are gen-

erally taken as constants for present data for these variables. Technologies that are not yet commercially available are generally excluded from energy efficiency potential studies. In this same vein, technologies included in studies are assumed to be constant in terms of their performance and costs. Thus most existing energy efficiency potential studies—many of them extending 15–20 years into the future—fail to account for continued improvements of existing technologies and introduction of new, much more efficient technologies. As a concrete example, LED lighting is currently a technology on the cusp of major breakthroughs in terms of customer applications and commercial availability. Existing studies of energy efficiency potential generally do not include this technology as it was not commercially available at the inception of the studies.

A related problem is reflected in assumptions used about the cost of energy efficiency. Studies rely on projected costs of energy efficiency—not realized (actual) costs, which typically may be lower than projected and also may decrease over time. For example, compact fluorescent light bulbs show rapid actual price decreases since their introduction over a decade ago. Such decreases generally are not captured in energy efficiency potential studies; costs are held constant in real terms over the period of the study. While determining changes in technology costs is quite difficult, that does not justify relying on the conventional cost projections. This issue needs further investigation, but it is important in this context to note that technology cost changes will affect energy efficiency potential.

Existing studies ignore non-energy benefits, e.g., increased thermal comfort, increased productivity and environmental benefits. Such benefits are difficult to quantify and are often mentioned as non-quantifiable factors.

Existing studies do not recognize benefits of reducing other criteria pollutants associated with fossil fuel combustion. The societal cost of emitting a ton of

mercury, sulfur oxide or nitrogen oxide varies for each pollutant and depends on many contributing factors. Despite the complexity of determining a total cost, a kWh saved from efficiency efforts is a kWh that does not emit pollutants into the environment (nor require remediation, combustion modifications nor post-combustion scrubbing).

Past studies largely ignore customer behavioral change, a rapidly emerging new program focus. The rapid change in consumer attitudes about the environment and climate change has created significant new opportunities to increase efficiency over the business-as-usual mindset. In fact there is evidence that consumers, in some cases, are taking action with respect to efficiency or renewable energy that would not be supported by traditional cost effectiveness studies that are the basis for potential studies. Consumers are clearly acting on many of the “non-quantifiable” benefits of efficiency. The increasing use of community energy programs, “blitz” program concepts and feedback mechanisms will take advantage of this opportunity. In addition, the adoption of smart grid technologies and advanced meters will enable significantly increased ability for consumers and businesses to more effectively control usage. Current studies of feedback approaches show reductions of up to 18 percent of load when both feedback and controls are available to consumers. (Neenan et al. 2009)

Behavior change is especially difficult to model because over time what now might be considered a change in typical behavior might eventually become the norm. The issue is when a behavior change is an innovation, and when it becomes part of the baseline. This issue, too, needs further research.

PAST ENERGY EFFICIENCY PROGRAM RESULTS AS PREDICTORS OF FUTURE PROGRAM PERFORMANCE

Past program results are not necessarily good indicators of future performance for the simple fact that past results reflect past funding levels and goals, not

future funding levels and goals that may be dramatically different.

The conditions and objectives of energy efficiency programs today and into the future are dramatically different than those of past and most present efforts. Witness how energy efficiency program budgets have been established in most jurisdictions. Funding levels have generally been set according to the policy question, “How much can we afford?” rather than “How much do we need?” or “How much can we buy to meet this need?” These questions frame funding decisions much differently—yielding potentially very different results.

A key objective of past programs was to achieve high cost effectiveness—that is, a low cost of saved energy (Figure 1 shows this cost to be in the range of 2 to 4 cents/kWh for comprehensive program portfolios in service areas with a long record of program delivery) or high benefit-to-cost ratios (at least 2:1 and in many cases 3:1 or higher). This objective has been driven by numerous reasons, but means that significant amounts of cost-effective energy efficiency resources have not been sought or captured by past programs. To achieve the more aggressive goals established by the MGA and policymakers elsewhere in the U.S., programs must move farther up the cost curves to capture energy efficiency resources—resources that are more costly but are still cost effective compared to supply or other options.³

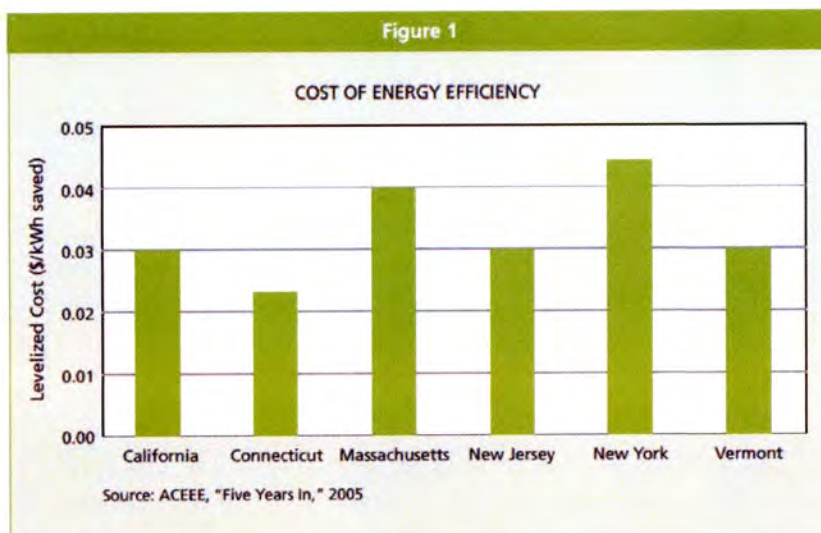
Recent McKinsey reports on carbon mitigation show energy efficiency strategies as significantly lower cost than other low carbon generation strategies.⁴ Recent data collected from existing energy efficiency programs across the US underscore this issue.

COMPARING MGA GOALS TO EXISTING AND PENDING STATE POLICY GOALS FOR ENERGY EFFICIENCY

The gaps and limited number of truly comparable studies of energy efficiency potential in the Midwest limits our ability to assess the magnitude of savings

³Utilities are not required to show that investments in supply resources meet benefit-to-cost ratios of 2:1.

⁴See Version 2 of the Global Greenhouse Gas Abatement Cost Curve. 2009. McKinsey & Company.



possible from energy efficiency improvements relative to the MGA goals. What we found is that existing studies of the achievable energy efficiency—the most relevant metric for comparison to the MGA’s policy goals—suggest slightly less than 1 percent savings per year. For three leading states in the Midwest in terms of past and on-going energy efficiency programs, we found that actual savings for 2007 (the most recent year for which data are available) were 0.7 percent each for three states (Iowa, Minnesota and Wisconsin).

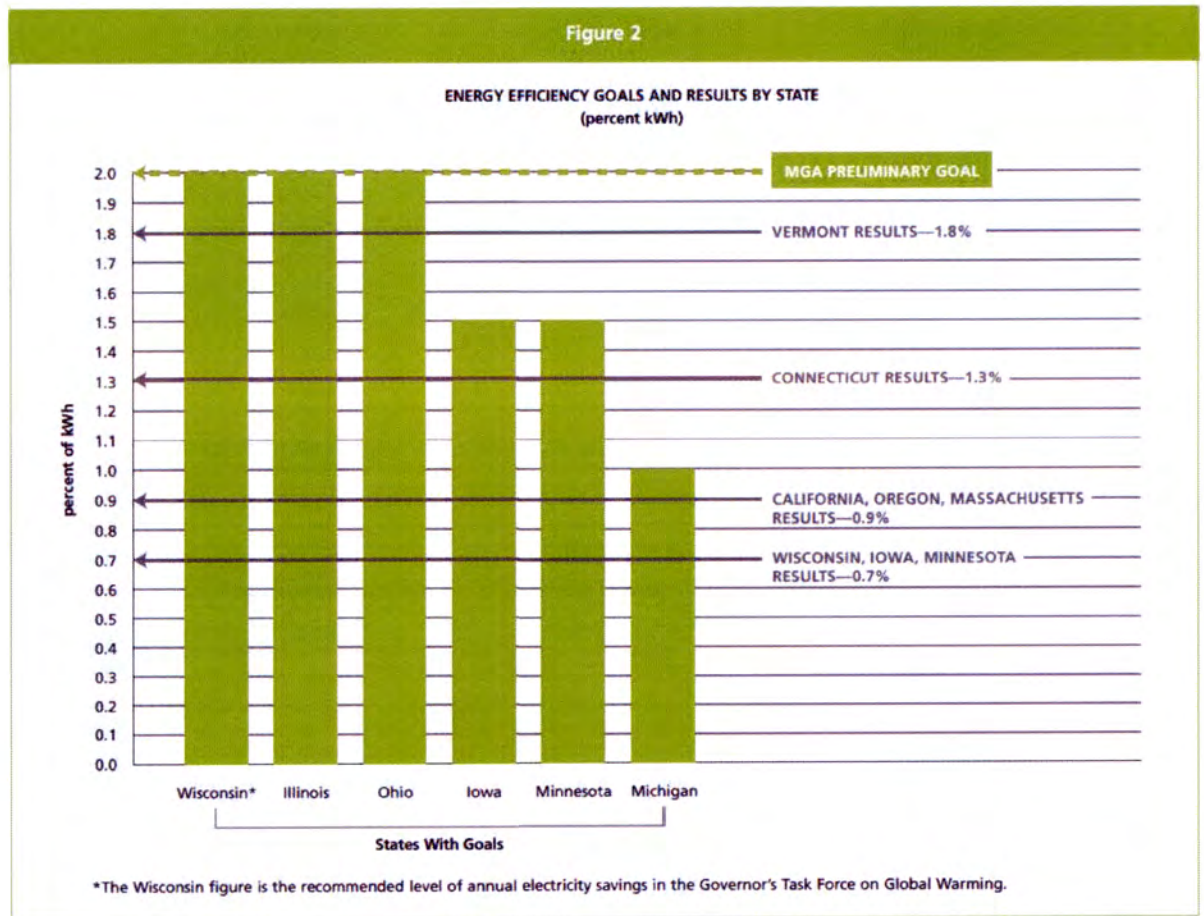
Broadening the set of energy efficiency potential studies to include non-Midwestern states, we find that the top performers estimated an average annual achievable savings of 1.5 percent. The MGA goals—two percent savings per year—are clearly and significantly higher than most results achieved to date, although a handful of states have reached annual savings greater than one percent and one state (Vermont) has nearly reached two percent (for 2008, not included in Table 4). Figure 2 (page 20) shows Midwestern states’ annual goals from current or pending legislation and initiatives, compared to the MGA target, as well as the achieved annual savings of states from across the nation.

The obvious questions are, “Are the two percent savings goals realistic?” and “Are they too high?”

We believe that the MGA goals are realistic for two key reasons: (1) as noted before, existing energy efficiency potential studies are very conservative, and (2) existing program activity levels have not targeted this level of savings. The level of savings that states have achieved to date is the result of explicit decisions to limit energy efficiency

funding to small percents of utility revenues. The savings levels are not a result of any physical, engineering or economic limit on the amount of cost-effective energy efficiency that could be acquired. In addition, the MGA targets include programs and approaches which may be outside the scope of those included in the potential studies we reviewed.

Finally we offer an example that we believe illustrates what is possible with a comprehensive, massive effort at reducing energy use through energy efficiency and conservation. In 2000–2001 California faced an electricity reliability crisis. The state was threatened with dire predictions of massive rolling outages due to a number of convergent conditions. In response California’s utilities and state government enacted an unprecedented level of energy efficiency and conservation programs—spending about \$1 billion on such efforts—to keep the electricity flowing and avoid outages. The results of this effort were dramatic and clearly helped avoid the dire outcomes that had been forecasted (Kushler and Vine 2003). The programs and policies enacted yielded unprecedented savings—a 6.7 percent reduction in total electricity use in 2001 with an average summertime peak demand savings of 10 percent with a maximum peak demand reduction achieved in one period of



14 percent (Kushler et al. 2002). These were the aggregate impacts of energy efficiency improvements, customer energy conservation, and demand response/load management (efforts that target peak demand reduction). While this was perhaps a one-time achievement due to emergency conditions, it does illustrate clearly what is possible for at least a short period. It certainly suggests that higher levels of customer energy savings

can be achieved through programs and policies than the levels shown by more recent results in our set of leading states (*Table 4*). The levels of savings achievable are clearly a function of programmatic efforts and associated budgets. Exactly how much savings can be achieved on a sustainable basis over an extended period remains mostly an unresolved question, however.

Changing the Paradigm

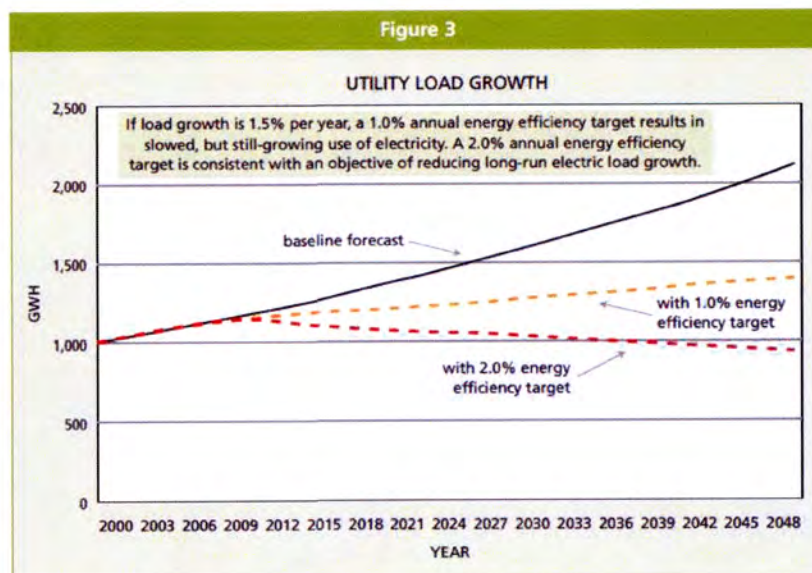
Given concerns about the impact of utility emissions contributing to global climate change, one objective could be to employ enough cost-effective energy efficiency to not only slow the growth rate of electricity consumption, but to reverse the trend so that growth is negative. We can achieve this via aggressive promotion of higher levels of energy efficiency. An analysis of expected utility load growth is illustrative.

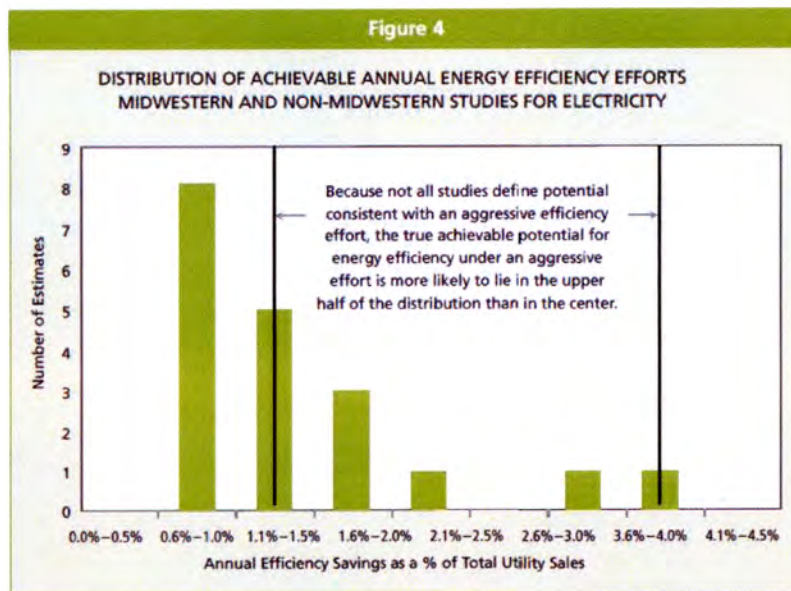
For example, our sample utility has baseline growth of 1.5 percent per year, typical of many Midwestern utilities. Note in Figure 3 the dramatic difference in long-term sales growth under a one percent annual energy efficiency target versus that which results from a two percent annual target. The one percent goal slows, but does not reverse load growth. The two percent goal delivers the desired long-term reduction in load. In other words, the two percent goal allows us to achieve this objective; the one percent goal does not.

The point of this illustration is to show that it is the policy objective that determines the savings target. We can make this sort of policy determination without any reference to energy efficiency potential studies. If the objective is to reduce electric load growth so as to reduce utility emissions, the efficiency goal must be devel-

oped in consideration of the load forecast. This is no better or no worse than relying on potential studies. It is merely another way of framing the problem.

While the graph depicts what has been typical load growth for Midwestern utilities, recent economic conditions may have altered this baseline growth. Currently, many Midwestern utilities are experiencing sales declines due to load reductions resulting from large industrial customers shutting plants or slowing production. This does not mean that energy efficiency is no longer needed. The size of the energy efficiency opportunity will be less but the need to offer energy efficiency services to all customers will be important to keep utility bills affordable in the long run and to address carbon mitigation.





The amount of achievable energy efficiency is primarily a function of financial investment, programmatic efforts and political will. That is, energy efficiency impacts are heavily driven by policy decisions. Put most directly, utilities and policymakers create their own energy futures. Utilities and policymakers can increase funding for energy efficiency programs, they can offer new programs, and they can change program evaluation protocols to make them more supportive of energy efficiency efforts. New and emerging technologies can be developed and implemented by customers through increased levels of research and development.

We should not be overly influenced by low or even mid-point estimates of energy efficiency potential. Since some potential studies apply a more passive, *exogenous* view of energy efficiency, while others take a more aggressive, *endogenous* perspective, it would be a mistake to look at the central tendency of potential studies and conclude that it represents the achievable potential under an aggressive policy.

The histogram in Figure 4 shows the distribution of achievable energy efficiency for the studies mentioned

in this report. If we look at the data in terms of the *reasonable upper limit* on what we could expect to achieve, then we should pay more attention to the right side of the distribution. This is likely to be where the estimates based on aggressive efforts are likely to lie.

The recent study from the Energy Center of Wisconsin, *Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin for the Years 2012 and 2018*, is an example of a potential study that estimates what we can

achieve by implementing more aggressive energy efficiency programs. The results show that Wisconsin can achieve annual energy savings of 1.6 percent of total electricity sales and 1.0 percent of total natural gas sales. In contrast, an earlier study conducted in 2005 by the Energy Center of Wisconsin found a range of annual electricity savings of 0.5 percent to 0.7 percent. Both studies estimated cost-effective achievable energy efficiency. However, the major changes in methodology in the most recent study reflected changing policy objectives for pursuing energy efficiency savings and included:

- quantifying the environmental benefits of avoided carbon emissions and
- querying experts on the savings that could be achieved under an aggressive policy and program scenario, one that lifts the constraints currently placed on these programs.

The results show that Wisconsin can approach the MGA's two percent goal with cost-effective energy efficiency programs. If potential energy savings resulting from changing building codes and appliance standards, and changes in our energy-using behavior are thrown into the mix, then we can surpass the two percent goal.

ROADMAP TO SUPPORT MGA POLICY GOALS

We believe the following actions will provide insight on the achievable potential for energy efficiency to meet the two percent annual savings goal established in the Energy Security and Climate Stewardship Platform.

1. Commission energy efficiency potential studies for the region that:

- Include forward looking avoided costs when assessing how much energy efficiency would be cost-effective—using ranges may be helpful. Studies should also examine a low-carbon generation cost as one cost comparison
- Fully incorporate carbon costs in the analysis—exploring ranges of possible, likely outcomes.
- Include reasonable assumptions on energy efficiency technology improvements and resulting costs over time—and better capture advanced, integrated packages of measures.
- Attempt to reflect the new and different social/political and economic contexts surrounding energy and energy efficiency.
- Avoid discounting future environmental benefits to recognize that the present value of environmental damage actually increases over time.
- Make an effort to collect current baseline data. Studies often use data that is over 10 years old due to lack of ongoing research.
- Incorporate expert opinions in the study rather than relying solely on the preprogrammed calculations in a potential model.
- Incorporate the potential for behavior based strategies to enhance efficiency efforts. Such strategies can include providing indirect or direct feedback on usage and pricing and the ability to directly control usage.
- Include full, comprehensive sets of markets and customer end-uses.

- Explore a range of benefit-cost constraints to understand how these constraints affect the estimated results. Not all energy use decisions are based on a TRC or other benefit-cost test. In addition cost is not always the barrier to increasing energy efficiency.

2. Monitor leading states (not just in the Midwest) for the energy efficiency results they achieve as a result of higher, more aggressive energy efficiency goals.

3. Sponsor research to understand better how energy is used and how policies and programs influence that use including: trends in technology adoption, effectiveness of building codes on upgrading building standards and building stock and how behavior-based programs influence and accelerate more efficient energy use.

The two percent energy efficiency savings target established in the Energy Security and Climate Stewardship Platform is aggressive but also achievable and a necessary goal if the Midwest is to significantly reduce its carbon emissions. Beyond the realm of the potential study, there is a growing body of literature showing that energy efficiency is the least-cost resource for reducing our carbon emissions and for which there are existing technologies that can immediately and cost-effectively reduce our energy use.⁵ The Chicago Council on Global Affairs lists specific energy efficiency technologies for the Midwest as leading strategies for carbon abatement. Explicit recognition of the value of energy efficiency compared to other abatement strategies will increase the results of future estimates of energy efficiency potential. Further, companion efforts to utility programs can accelerate program results due to increased awareness of the broader benefits of energy efficiency to the environment and to the economy of the Midwest. ■

⁵Embracing the Future: The Midwest and a New National Energy Policy. 2009. The Chicago Council on Global Affairs, Chicago, IL.

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Annotated Bibliography of Midwestern Energy Efficiency Potential Studies Reviewed

ENERGY EFFICIENCY AND CUSTOMER-SITED RENEWABLE ENERGY: ACHIEVABLE POTENTIAL IN WISCONSIN 2006–2015

STATE: Wisconsin

STUDY NAME: Energy Efficiency and Customer-Sited Renewable Energy: Achievable Potential in Wisconsin 2006–2015

AUTHOR: Energy Center of Wisconsin

YEAR COMPLETED: 2005

PERIOD OF STUDY: 2006–2015

FUELS: Electricity, Natural Gas

SECTORS: Residential, Commercial/Industrial

PURPOSE OF STUDY: “To provide information to policymakers, regulators, utilities and other energy stakeholders in Wisconsin to determine the appropriate level of investment in Wisconsin’s energy efficiency and renewable energy ‘public benefits’ programs.”

METHODOLOGY: The Energy Center of Wisconsin used a market opportunity approach to estimate achievable energy efficiency savings. It sought input from diverse stakeholders on the most cost-effective markets, selected 30 markets, and determined that these markets covered most major opportunities. Missing markets totaled 10–25 percent of the energy efficiency potential. For the renewable energy market, the Energy Center chose the six most promising technologies.

The Energy Center then studied these 36 markets, outlined likely program approaches, assessed their probable costs and energy savings, and aggregated the results. The technologies selected were feasible, cost-effective, and likely to be accepted by the market. The analysis excluded free riders and included spillover effects (participation without incentives).

TECHNICAL POTENTIAL: Not given

ECONOMIC POTENTIAL: Not given

ACHIEVABLE POTENTIAL: The percentage of reduction in demand in the final year of the analysis period was 4.2–8.0 percent for electricity demand, 6.1–9.2 percent for electric energy, and 3.0–5.2 percent for natural gas energy. The cumulative potential over the time period divided by the number of years was not given.

AVOIDED COST VALUES: The target avoided costs were \$60–80/kW/year for electricity demand, 4–8 cents/kWh for electric energy, and 60–140 cents/therm for natural gas energy.

CARBON COSTS: Discussed as factor but not quantified

ILLINOIS RESIDENTIAL MARKET ANALYSIS

STATE: Illinois

STUDY NAME: Illinois Residential Market Analysis: Final Report

AUTHOR: MEEA

YEAR COMPLETED: 2003

PERIOD OF STUDY: Not specified

FUELS: Electricity, Natural Gas

SECTORS: Residential

PURPOSE OF STUDY: Rising energy costs and global warming have made this an important time to take steps toward energy efficiency goals. This study identifies “opportunities to fuel the growth of energy efficiency in Illinois.... The findings can be used to inform impending decisions about how public and private money will be spent to promote energy conservation in Illinois.”

METHODOLOGY: “MEEA used a modified stratification sampling strategy to identify and recruit single-family homeowners in five different geographic segments of the state. Within each of those segments, towns or cities with high ratios of owned homes to rental units were identified, and then a random sampling of phone numbers... was used to recruit homeowners.” MEEA conducted a walk-through audit of each home and surveyed the

homeowners. 309 site visits and surveys took place. Researchers used DOE2 modeling to analyze the technical, economic and market potential for savings associated with 34 home improvement measures. MEEA then selected 19 of the measures for further analysis. The results were weighted and averaged for the entire state.

FINDINGS: The cumulative potential savings over the time period divided by the number of years was not given. For the 19 measures which were analyzed in depth:

TECHNICAL POTENTIAL: 67 percent of demand (at the end of the period studied)

ECONOMIC POTENTIAL: 36 percent of demand (at the end of the period studied)

ACHIEVABLE POTENTIAL: 1.5 percent of demand (at the end of the period studied)

AVOIDED COST VALUES: The top 19 measures could save \$17,637,000, 179.5 MW/year, 164,471 MWh/year, and 4,403 kTherms/year.

CARBON COSTS: Not given

ASSESSMENT OF ENERGY EFFICIENCY POTENTIAL: 2006–2025

STATE: Ontario, CA

STUDY NAME: Assessment of Energy Efficiency Potential: 2006–2025

AUTHOR: ICF Consulting

YEAR COMPLETED: 2005

PERIOD OF STUDY: 2006–2025

FUELS: Electricity

SECTORS: Residential, Commercial/Industrial

PURPOSE OF STUDY: “The [Ontario Power Authority] seeks recommendations [for] the development of conservation targets through 2025 within the context of already-existing efficiency goals.... The OPA seeks further understanding of the energy efficiency portfolio options at its disposal and the risks inherent in each option. Moreover, the OPA requires explicit identification of the action required by government to enact these options.”

METHODOLOGY: Researchers established a baseline energy demand forecast segmented by sector, sub-sector, and end use. The study used published growth rates for employment and households. The baseline forecasts were segmented based on the type of technology used by the customer. The organization used a list of energy efficiency measures that had been screened

for applicability and feasibility. These measures were then screened for cost-effectiveness using the Technical Cost Test (TCT). Measures that passed this test became part of the final set of efficiency measures. The researchers analyzed several levels of incentive-based support and also included the effects of new technologies.

TECHNICAL POTENTIAL: Energy efficiency measures could eliminate 21–36 percent of residential demand, 18–41 percent of commercial demand and 17–38 percent of industrial demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 1.05–1.8 percent for the residential market, 0.9–2.05 percent for the commercial market, and 0.85–1.9 percent for the industrial market.

ECONOMIC POTENTIAL: Energy efficiency measures could eliminate 10.6–30 percent of residential demand, 12.7–35 percent of commercial demand, and 6.2–32 percent of industrial demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 0.53–1.5 percent for the residential market, 0.635–1.75 percent for the commercial market, and 0.31–1.6 percent for the industrial market.

ACHIEVABLE POTENTIAL: Energy efficiency measures could eliminate 5.3–21.7 percent of residential demand, 5.1–17 percent of commercial demand; and 2–19 percent of industrial demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 0.265–1.085 percent for the residential market, 0.255–0.85 percent for the commercial market, and 0.1–0.95 percent for the industrial market.

AVOIDED COST VALUES: Not given

CARBON COSTS: Not given

KANSAS ENERGY COUNCIL DSM POTENTIAL STUDY AND PLAN

STATE: Kansas

STUDY NAME: Kansas Energy Council DSM Potential Study and Plan

AUTHOR: Summit Blue Consulting

YEAR COMPLETED: 2008

PERIOD OF STUDY: 2008–2028

FUELS: Electricity, Natural Gas

SECTORS: Residential, Commercial/Industrial

PURPOSE OF STUDY: The Kansas Energy Council hired Summit

Blue Consulting and Energy Insights to develop an energy efficiency potential study that would “[provide] technical, economic and market potential for metropolitan/suburban and rural Kansas by end use in the residential market and by industry segment and end use in the C&I markets.” The authors mention that “several Kansas utilities are currently conducting energy efficiency and/or demand response programs. Several additional Kansas utilities have submitted energy efficiency and demand response programs to the Kansas Corporation Commission for approval.”

METHODOLOGY: Summit Blue took the following steps:

1. conducting a Midwest-focused DSM benchmarking and best practices analysis,
2. developing baseline consumption profiles and simulation model specifications,
3. simulating energy consumption in buildings,
4. deciding which DSM measures were appropriate for Kansas (based on the simulations),
5. analyzing cost-effectiveness per measure and sector, and
6. estimating DSM potentials for residential and non-residential customers.

TECHNICAL POTENTIAL: Energy efficiency measures could eliminate 43 percent of residential demand and 34 percent of non-residential demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 2.15 percent for the residential electricity market, 2.95 percent for the natural gas residential market, 1.7 percent for the non-residential electricity market, and 2.25 percent for the non-residential natural gas market.

ECONOMIC POTENTIAL: Energy efficiency measures could eliminate 35 percent of residential demand for electricity, 46 percent of residential demand for natural gas, 34 percent of non-residential demand for electricity, and 45 percent of non-residential demand for natural gas during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 1.75 percent for the residential electricity market, 2.3 percent for the residential natural gas market, 1.7 percent for the non-residential electricity market, and 2.25 percent for the non-residential natural gas market.

ACHIEVABLE POTENTIAL: This varied depending on the incentives supplied (see pages E-9, E-13, E-14 and E-18.) Energy efficiency measures could save 11–25 percent of residential electricity demand, 29–46 percent of residential natural gas demand, 17–29 percent of non-residential electricity demand, and 19–35 percent of non-residential natural gas demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 0.55–1.25 percent for the residential electricity market, 1.45–2.3 percent of

the residential natural gas market, 0.85–1.45 percent of the non-residential electricity market, and 0.95–1.75 percent of the non-residential natural gas market.

AVOIDED COST VALUES: Not given

CARBON COSTS: Not given

DUKE ENERGY INDIANA DSM MARKET ASSESSMENT AND DSM ACTION PLAN: FINAL REPORT

STATE: Indiana

STUDY NAME: Duke Energy Indiana DSM Market Assessment and DSM Action Plan: Final Report

AUTHOR: Summit Blue Consulting and WECC

YEAR COMPLETED: 2007

PERIOD OF STUDY: 2008–2027

FUELS: Electricity

SECTORS: Residential, Commercial/Industrial

PURPOSE OF STUDY: “This study was conducted in response to a May 25, 2005 Indiana Utility Regulatory Commission order regarding Duke’s April 2, 2004 filing to expand its Indiana DSM programs and to change certain DSM financial arrangements in Indiana, such as recovery of lost revenues due to DSM programs.”

METHODOLOGY: Summit Blue took the following steps:

1. conducting a Midwest-focused DSM benchmarking and best practices analysis,
2. developing baseline consumption profiles and simulation model specifications,
3. simulating energy consumption in buildings,
4. deciding which DSM measures were appropriate for Indiana (based on the simulations),
5. doing a cost-benefit analysis, and
6. estimating DSM potentials for residential and small commercial/industrial customers.

WECC assisted Summit Blue with its market assessment, reviewed Duke’s existing DSM programs and recommended changes, developed new program designs, and built a program portfolio for the recommended action plan.

The researchers considered emerging technologies to some extent.

TECHNICAL POTENTIAL: Assessed, but not given.

ECONOMIC POTENTIAL: Assessed, but not given.

ACHIEVABLE POTENTIAL: Energy efficiency measures could

eliminate 15 percent of residential electricity demand and 9 percent of small commercial/industrial electricity demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 0.75 percent for the residential electricity market and 0.45 percent of the small commercial/industrial electricity market.

AVOIDED COST VALUES: The avoided transmission/distribution costs in Year 25 are \$30.59/kW. See page 79 for details.

CARBON COSTS: Not given

2006 MISSOURI STATEWIDE RESIDENTIAL LIGHTING AND APPLIANCE EFFICIENCY SATURATION STUDY

STATE: Missouri

STUDY NAME: 2006 Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study

AUTHOR: RLW Analytics

YEAR COMPLETED: 2006

PERIOD OF STUDY: N/A

FUELS: This study is organized by appliance type rather than by fuel.

SECTORS: Residential

PURPOSE OF STUDY: To serve a group of utilities in Missouri by providing “baseline information on residential appliance, building, equipment and lighting saturations and efficiencies... for use in understanding future energy savings potential in the residential sector.” Two of the study’s goals were: first, to develop a web-based tool to allow utility staff to visualize potential energy savings scenarios, and second, to calculate potential analyses for energy efficiency opportunities.

METHODOLOGY: The study is based on energy audits and surveys of over 300 homes. RLW analyzed 32 home improvement options in the first iteration of the process. RLW calculated the technical, economic and market potential of the energy efficiency improvements (which combined results for several different fuels.) The market potential calculations assumed rebates of 50 percent of the differential costs.

FINDINGS: The technical, economic and market potential of each residential energy efficiency improvement (i.e., replacing appliances) were analyzed separately; combined impacts were not given. For more information about the individual measures, refer to pages 136–138.

AVOIDED COST VALUES: Not given

CARBON COSTS: Not given

ASSESSMENT OF ENERGY AND CAPACITY SAVINGS POTENTIAL IN IOWA

STATE: Iowa

STUDY NAME: Assessment of Energy and Capacity Savings Potential in Iowa

AUTHOR: Quantec, Summit Blue Consulting, Nexant, Inc., A-TEC Energy Corporation and Britt/Makela Group

YEAR COMPLETED: 2008

PERIOD OF STUDY: 2008–2018

FUELS: Electricity, Natural Gas

SECTORS: Residential, Commercial, Industrial

PURPOSE OF STUDY: “To conduct an assessment of technical and economic opportunities for electric and gas energy efficiency and renewable resources in the service territories [of three utilities].” The utilities are required to pursue energy efficiency opportunities.

METHODOLOGY: The methodology combines “top-down” methods, consisting of analysis of current utility load forecasts, with “bottom-up” methods analyzing the potential impacts of demand-side and supplemental resource technologies on end use of energy resources. The “bottom-up” results were aggregated to produce macro-scale estimates. The researchers assessed technical and economic potential for residential, commercial and industrial sectors for each utility, subdividing them by fuel type. The study generally did not consider the impact of new technologies.

TECHNICAL POTENTIAL: Energy efficiency measures could eliminate 46 percent of residential electricity demand, 40 percent of residential natural gas demand, 30 percent of commercial electricity demand, 38 percent of commercial natural gas demand, 11 percent of industrial electricity demand, and 18 percent of industrial natural gas demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was not given.

ECONOMIC POTENTIAL: Energy efficiency measures could eliminate 30 percent of residential electricity demand, 28 percent of residential natural gas demand, 17 percent of commercial electricity demand, 26 percent of commercial natural gas demand, 10 percent of industrial electricity demand, and 18 percent of industrial natural gas demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was not given.

ANNOTATED BIBLIOGRAPHY

ACHIEVABLE POTENTIAL: Not given

AVOIDED COST VALUES: Not given

CARBON COSTS: Not given

MIDWEST RESIDENTIAL MARKET ASSESSMENT AND DSM POTENTIAL STUDY

STATE: Midwest (nine states)

STUDY NAME: Midwest Residential Market Assessment and DSM Potential Study

AUTHOR: MEEA

YEAR COMPLETED: 2006

PERIOD OF STUDY: 2006–2025

FUELS: Electricity, Natural Gas

SECTORS: Residential

PURPOSE OF STUDY: To “characterize the Midwest residential market, including estimating saturation rates for existing energy efficiency technologies, products, practices and behavior;” to evaluate efficiency opportunities; to estimate a baseline for the purpose of assessing future residential DSM programs; and to compare other Midwest states to Xcel Energy’s service area in Minnesota.

METHODOLOGY: The authors used data and results from four recent Midwest residential market assessments to characterize those four states. The team also surveyed energy auditors and homeowners. They then developed a mathematical model of DSM potential in the Midwest.

TECHNICAL POTENTIAL: Energy efficiency measures could eliminate 24 percent of residential electricity demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 1.18 percent for electricity and 2.33 percent for natural gas.

ECONOMIC POTENTIAL: Not given

ACHIEVABLE POTENTIAL: Energy efficiency measures could save 10.3 percent of residential electricity demand and 25.2 percent of residential natural gas demand during the final year of the period studied. The cumulative potential over the time period divided by the number of years was 0.515 percent for electricity and 1.26 percent for natural gas.

AVOIDED COST VALUES: Not given

CARBON COSTS: Not given

MINNESOTA STUDIES

STATE: Minnesota

STUDY NAME: Data not published; presented at ACEEE Summer Study

AUTHOR: Summit Blue Consulting

YEAR COMPLETED: 2003

PERIOD OF STUDY: Not given

FUELS: Electricity

SECTORS: Not given

PURPOSE OF STUDY: Not given

METHODOLOGY: Not given

TECHNICAL POTENTIAL: The cumulative potential over the time period divided by the number of years was 3.90 percent for electricity.

ECONOMIC POTENTIAL: The cumulative potential over the time period divided by the number of years was 0.70 percent for electricity.

ACHIEVABLE POTENTIAL: Not given

AVOIDED COST VALUES: Not given

CARBON COSTS: Not given

ENERGY EFFICIENCY POTENTIAL IN WISCONSIN (2009)

STATE: Wisconsin

STUDY NAME: Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin for the Years 2012 and 2018

AUTHOR: Energy Center of Wisconsin, et al

YEAR COMPLETED: 2009

PERIOD OF STUDY: 2008–2018

FUELS: Electricity, Natural Gas

SECTORS: Residential, Commercial, and Industrial

PURPOSE OF STUDY: “The Public Service Commission of Wisconsin (PSCW) retained the Energy Center of Wisconsin (Energy Center) for the purpose of analyzing the potential for Wisconsin to increase its use of energy efficiency resources.”

METHODOLOGY: The study analyzed the potential for increased use of high-efficiency measures in the various sectors. For the residential sector, a bottom-up approach was used, aggregating savings potential associated with individual types of energy-using equipment. For the commercial, industrial, and agricultural sectors a top-down approach was used, which disaggregated savings estimates based on an assumed distribution of energy use within each market segment.

ECONOMIC POTENTIAL: Energy efficiency measures could eliminate 18 percent of statewide electricity use and 16 percent of natural gas use.

ACHIEVABLE POTENTIAL: The study found that energy efficiency could reduce overall electricity use by 1.6 percent per year for both energy and peak demand, and natural gas use by 1.0 percent per year. These estimates do not include the potential impact of behavior-based programs or advanced rate designs. Results by sector for electricity are: residential 1.0 percent, commercial 2.0 percent, industrial 1.6 percent, and agricultural 2.4 percent. Natural gas results by sector are: residential 0.2 percent, commercial 1.0 percent, industrial 1.7 percent, and agricultural 0.9 percent.

AVOIDED COST VALUES:

- Avoided electric energy and generation cost—\$0.0546 per kWh
- Avoided electric transmission and distribution cost—\$30 per kW-yr
- Avoided natural gas cost—\$0.84 per therm

CARBON COSTS:

- Electricity—\$0.025 per kWh
- Natural gas—\$0.176 per therm

ENERGY EFFICIENCY POTENTIAL FOR IOWA MUNICIPAL UTILITIES (2009)

STATE: Iowa

STUDY NAME: Energy Efficiency and Demand Response Potential for Iowa Municipal Utilities for the Years 2012 and 2018

AUTHOR: Energy Center of Wisconsin, et al

YEAR COMPLETED: 2009

PERIOD OF STUDY: 2008–2018

FUELS: Electricity, Natural Gas

SECTORS: Residential, Commercial, and Industrial

PURPOSE OF STUDY: “The Iowa Association of Municipal Utilities (IAMU) retained the Energy Center of Wisconsin (Energy Center) to conduct an empirical assessment of energy efficiency and demand response potential in IAMU member service territory.”

METHODOLOGY: The study analyzed the potential for increased use of high-efficiency measures in the various sectors. For the residential sector, a bottom-up approach was used, aggregating savings potential associated with individual types of energy-using equipment. For the commercial, industrial, and agricultural sectors a top-down approach was used, which disaggregated savings estimates based on an assumed distribution of energy use within each market segment.

ECONOMIC POTENTIAL: Energy efficiency measures could eliminate 22 percent of member electricity use, 38 percent of member electric peak demand, and 22 percent of member natural gas use.

ACHIEVABLE POTENTIAL: The study found that by the year 2018 energy efficiency could reduce overall electricity use by 1.2 percent per year, electric peak demand by 1.8 percent, and natural gas use by 1.8 percent per year. Results by sector for 2018 electricity are: residential 0.8 percent, commercial 1.5 percent, and industrial 1.2 percent. Natural gas results by sector are: residential 2.2 percent, commercial 1.5 percent, and industrial 1.6 percent.

AVOIDED COST VALUES:

- Avoided electric energy and generation cost
 - On-peak summer—\$0.069 per kWh
 - Off-peak summer—\$0.032 per kWh
 - On-peak winter—\$0.064 per kWh
 - Off-peak winter—\$0.035 per kWh
- Avoided electric transmission and distribution cost
 - On-peak summer—\$30 per kW-yr
 - Off-peak summer—\$0 per kW-yr
 - On-peak winter—\$30 per kW-yr
 - Off-peak winter—\$0 per kW-yr
- Externality factor
 - Electricity—\$0.0235 per kWh
 - Natural gas—\$0.067 per therm
- Avoided natural gas cost
 - Summer—\$0.89 per therm
 - Winter—\$1.00 per therm

CARBON COSTS:

- (used in sensitivity analysis only)
- Electricity—\$0.0235 per kWh
 - Natural gas—\$0.180 per therm

ASSESSMENT OF ACHIEVABLE POTENTIAL FROM ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS IN THE U.S.

STATE: National

STUDY NAME: Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.

AUTHOR: Electric Power Research Institute (EPRI)

YEAR COMPLETED: 2009

PERIOD OF STUDY: 2010–2030

FUELS: Electricity

SECTORS: Residential, Commercial, Industrial

PURPOSE OF STUDY: As energy efficiency is seen more and more as a solution for the contemporary challenges facing utilities, many states have passed, or are considering, legislation mandating energy efficiency savings levels. Such policies rely on sound estimates of the potential for energy efficiency. “To help address this need, the Electric Power Research Institute (EPRI) commissioned a study to assess the potential of electric end-use energy efficiency and demand response programs to mitigate the projected growth of U.S. electricity consumption and summer peak demand through 2030. A key objective of the study is to inform utilities, electric system operators and planners, policymakers, and other electricity sector industry stakeholders in their efforts to develop actionable savings estimates for end-use energy-efficiency and demand-response programs.”

METHODOLOGY: “The study applied two distinct approaches to estimate electric energy efficiency: one for residential and commercial buildings and another for industrial facilities. For the residential and commercial sectors, the study implemented a bottom-up approach for determining electric energy efficiency savings potential. The residential and commercial approach begins with a detailed equipment inventory (e.g., the number of refrigerators), the average unit energy consumption (per household or per square foot in the commercial sector), and the diversified load during the non-coincident summer peak. In each sector, annual energy use and peak demand are the product of the number of units and the unit consumption annually, and at peak. This process is repeated for all devices across vintages and sectors. AEO 2008 [Annual Energy Outlook] provided both the number of units and the unit consumption. Diversified peak-load estimates were also developed as part of the study. For the industrial sector, the study applied a top-down approach in which the sector forecast is allocated to end uses and regions.”

TECHNICAL POTENTIAL: 29.1 percent of total load (at the end of the period studied)

ECONOMIC POTENTIAL: 13.6 percent of total load (at the end of the period studied)

ACHIEVABLE POTENTIAL: 0.4 percent

AVOIDED COST VALUES: Not explicitly discussed.

CARBON COSTS: Not given

MINNESOTA GAS ENERGY EFFICIENCY POTENTIAL

STATE: Minnesota

STUDY NAME: Minnesota Gas Energy Efficiency Potential

AUTHOR: Navigant Consulting Inc. (NCI)

YEAR COMPLETED: 2009

PERIOD OF STUDY: 2009–2019

FUELS: Gas

SECTORS: Residential, Commercial, Industrial

PURPOSE OF STUDY: “Navigant Consulting, Inc. (NCI) worked with the three Minnesota gas utilities to develop estimates of the potential for gas energy efficiency including detailed analysis of existing gas use, available energy efficiency options, and policies and programs.”

METHODOLOGY: Program potentials are calculated based upon detailed analysis of gas use in Minnesota and the measures for cost effectively improving efficiency at the customer segment and end-use level. Steps included (1) Sales Profiles and Forecasts—Develop detailed estimates of gas use by customer segment and end-use; Reconcile with utility sales forecasts; Develop gas price forecasts (2) EE Technology—Identify energy efficiency technologies that will provide significant cost effective gas energy savings in Minnesota; Develop detailed data on current penetration, costs, energy savings and lifetimes (3) Technical & Economic Potentials—Forecasts for energy efficiency if all customers adopted all applicable measures: all measures, only cost-effective measures (4) Program Design—Interview stakeholders about strategies for improving current programs; Best practices in other programs; Develop recommended program improvements and estimated additional costs (5) Program Potentials—Forecast energy efficiency savings and costs for: current programs and improved programs (with several scenarios) (6) Recommendations—Provide recommendations on policy issues to complement programs.

FINDINGS: Potentials were calculated for each utility.

TECHNICAL POTENTIAL: 2009–2019 Cumulative savings potential: Utility 1: 37%, Utility 2: 29%, Utility 3: 33%

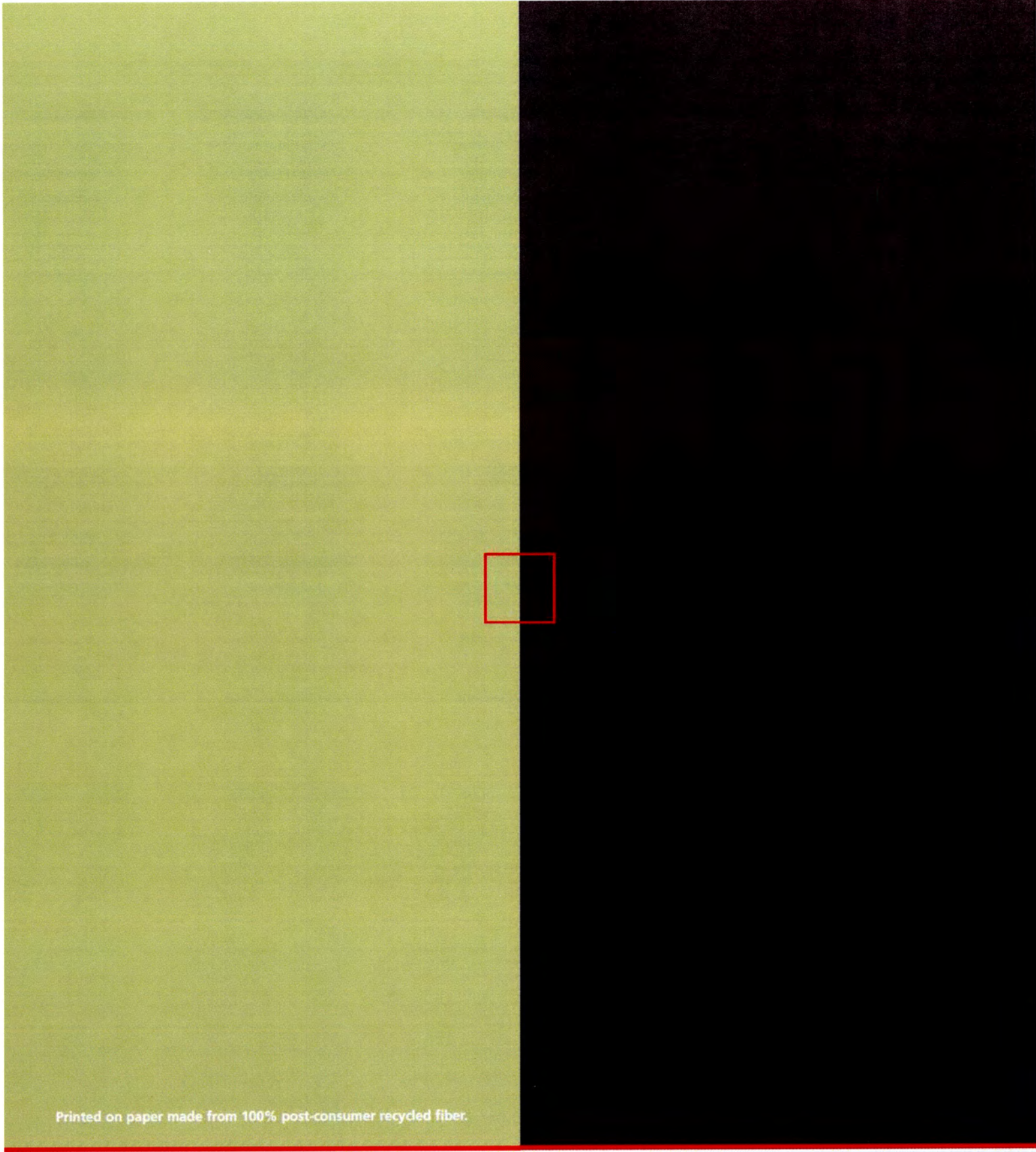
ECONOMIC POTENTIAL: 2009–2019 Cumulative savings potential: Utility 1: 29%, Utility 2: 22%, Utility 3: 23%

ACHIEVABLE POTENTIAL: 2009–2019 Annual savings potential: Utility 1: 1.7%, Utility 2: 1.2%, Utility 3: 1.6%

AVOIDED COST VALUES: Avoided cost values are not presented in dollars per energy unit. Instead they are presented as net benefits and are given for each utility across five scenarios.

CARBON COSTS: The potential range of carbon price is estimated to be \$20–50 per ton of CO₂.





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Schedule RAV-E4

Data Information Request
From Union Electric Company d/b/a Ameren Missouri
MPSC Case No. EO-2011-0271

Requested From: Office of Public Counsel – Tim Woolf

Requested By: Wendy Tatro

Date of Request: November 4, 2011

Information Requested:

Please provide any analysis OPC has performed or has had others perform on its behalf of the differences in the energy efficiency savings achieved by the states included in Figure 1 on page 7 as a function of retail rates, restrictions on and/or allowances for the kinds of measures included in the statistics, or any other differences that might explain differences in results.

Response:

Mr. Woolf has not created any documents containing analysis that he performed of the factors in each state that might explain the differences between the energy savings presented in Figure 1 of his testimony.

Response Provided By: Tim Woolf Date: November 23, 2011

NRDC Responses to Ameren UE Data Requests in MPSC Case No. EO-2011-0271

Prepared by Philip Mosenthal

Dated November 23, 2011

Ameren-NRDC-036

NRDC believes that Ameren Missouri has an obligation under the Missouri IRP guidelines to objectively analyze the least cost opportunities for meeting all energy resource needs in its territory, regardless of the possible or perceived impact on Company earnings. NRDC does not believe that an IRP is a commitment to fund DSM. Further, NRDC believes that the Company can propose regulatory solutions that would enable it to resolve any perceived negative impact on Company earnings through the MEEIA filing process.

Ameren-NRDC-037

Ameren Missouri is primarily responsible for protecting the interests of its shareholders. However, as part of its duty of protecting the public interest, MPSC has a role in ensuring reasonable and fair returns to shareholders to ensure long term public interests can be met by Ameren.

Ameren-NRDC-038

NRDC believes there could be other considerations contemplated by the language of section 22.010(2)(C) beyond the three explicitly stated. NRDC notes that this section directs quantification of "any other considerations which are critical to meeting the fundamental objective of the resource planning process." However, NRDC's Witness Mosenthal is not a lawyer and declines to speculate on the intent of this section beyond the language stated. NRDC notes that nothing in this section diminishes 22.010(2)(B) that establishes minimization of PVRR as the "primary selection criteria."

Ameren-NRDC-039

No.

Ameren-NRDC-040

N/A

Ameren-NRDC-041

As 22.010(2)(C) directs, the Company should quantify and analyze these other considerations. However, they do not remove the requirement of "minimization of PVRR as the *primary selection criteria*." Rather, these other considerations should

be reviewed, and appropriate solutions investigated and proposed that further the primary criteria of the IRP.

Ameren-NRDC-042

NRDC has not reviewed the Company's 2008 IRP as part of this proceeding.

Ameren-NRDC-043

NRDC believes the term "public interest," in the context of the generally understood role of regulators to ensure that utilities "serve the public interest," refers to the consumers of energy and/or citizens of the state under which regulation occurs. In other words, it distinguishes between — and is intended to balance — the regulated-monopoly Company's interests in maximizing shareholder profits with the interests of the "public." As such, while members of the public certainly could own utility shares, the regulatory distinction is between these potentially competing interests. NRDC agrees that addressing rate-of-return and other issues directly impacting utility shareholders are a key role of regulators. However, this role is in the context of protecting the "public interest" by ensuring a fair return that will provide the utility with necessary equity while avoiding unfair rates to consumers. We believe regulatory and judicial precedents support this distinction of "public" as separate from Company shareholders.

Ameren-NRDC-044

NRDC believes that analysis and quantification of the impact of the Preferred Resource Plan (or any other hypothetical plan or IRP outcome) on investors is a valid consideration under 22.010(2)(C). However, NRDC disagrees that a Company perception that any negative impact could not be addressed through appropriate regulatory mechanisms to ensure that the Company shareholder's and the public's interest are aligned should drive the results of the IRP. Rather, this quantification and analysis can and should allow the Company to both acknowledge the least cost solution, point out any problems this creates resulting from poor alignment of interests, and then propose solutions that would allow for a fair and reasonable approach to pursuing least cost resources.

Ameren-NRDC-045

Yes; this is reflected in 22.010(2)(B) and 22.010(2)(C)3.

Ameren-NRDC-046

NRDC can imagine a hypothetical case where rate impacts *could* be "more important" to plan selection than minimizing PVR. However, this would be under an extreme scenario not applicable to Ameren's IRP. For example, if EE could remove

virtually all building load through aggressive pursuit of net-zero buildings, but by doing so would result in extremely large rate increases on industrial process usage that might cripple the Missouri economy, that hypothetical scenario could result in rate impacts becoming as or more important than minimization of PVRR. NRDC notes that it has not objected to analysis of rate impacts by Ameren. Rather, it has questioned the presumption by Ameren that rates could not be increased to ensure a fair return to its shareholders from pursuit of DSM.

Ameren-NRDC-047

NRDC has not performed the analysis requested.

Ameren-NRDC-048

NRDC has not performed a detailed review of the KEMA 2010 potential study, nor performed any analysis of it.

Ameren-NRDC-049

No. Ultimate decisions about cost recovery must be made by the MPSC, and are not “assured” simply by a filing.

Ameren-NRDC-050

NRDC is aware of a dispute over the definition of lost revenue, but does not believe it jeopardizes adequate cost recovery. NRDC is also aware of an issue with the timeliness of recovery of lost revenue and incentives.

Ameren-NRDC-051

The requested analysis has not been conducted by NRDC.

Ameren-NRDC-052

NRDC has not developed a list, nor analyzed cost-effectiveness of such a list, of DSM technologies that it considers “emerging technologies.”