



Common Demand Response Practices and Program Designs

In October 2015, the Roadmap for Implementing Michigan’s New Energy Policy Steering Committee charged stakeholders with developing a vision and recommendations to promote demand response (DR) programs in Michigan. In response to this charge, stakeholders crafted their vision and recommendations (available on [the project website](#)) for demand response, but the group’s recommendations did not address one element of the steering committee’s charge. The steering committee’s unanswered question asked, “How should customers be compensated for participation in DR programs, and what should the penalties or other approaches to ensure adequate performance be?” In an effort to help stakeholders tackle this important question, the steering committee tasked the Michigan Public Service Commission (MPSC) staff Demand Response Team* to prepare a survey to describe current and—to the extent possible—best practices for demand response rate design. Building on staff’s initial research, Public Sector Consultants has expanded the scope of this report to include a national overview of DR programs and incorporated additional references to recent studies of DR program effectiveness. In addition to reporting on DR practices, MPSC staff also produced a sample DR rate tariff—based on current practices—to be used as a model in discussions of future DR programs in Michigan. This document will serve as a guide for stakeholders as they attempt to respond to this remaining question from the charge.

Overview of Demand Response Programs Nationwide

The Federal Energy Regulatory Commission (FERC)—in response to a Congressional mandate—publishes an annual *Assessment of Demand Response and Advanced Metering*. In this report, FERC details the deployment of advanced metering infrastructure (AMI or “smart meters”), the annual resource contribution from DR, potential for DR programs, and customer participation rates. According to the 2015 assessment, the annual potential for peak load reductions from DR dropped 4.9 percent from 2012 to 2013 due to lower reported savings from several utility programs (FERC December 2015). Despite the overall decline in the amount of DR resources available, overall enrollment in DR programs rose more than 60 percent during the same time period, see Exhibit 1.

* *** *DISCLAIMER* *** - This document, though compiled with input from Michigan Public Service Commission staff, is in no way intended to be construed as representative of the opinions of MPSC staff, the MPSC, or the Office of the Attorney General. This document is a summary of demand response practices from other states and while informative, the practices detailed in this report are not meant to be overt examples for Michigan’s future demand response programs.

EXHIBIT 1. Potential Peak Reduction from Retail Demand Response Programs and Customer Enrollment by NERC Region



Incentive-based Programs	Time-based Programs
Demand bidding and buyback	Critical-peak pricing with control
Direct load control	Critical-peak pricing
Emergency demand response	Peak-time rebate
Interruptible load	Real-time pricing
Load as capacity resource	Time-of-use pricing
Nonspinning reserves	System peak response transmission tariff
Regulation service	
Spinning reserves	

NERC Region	Annual Potential Peak Reduction (MW)	Percent Change 2012 to 2013	Enrollment in Incentive-based Programs (2013)	Percent Change in Incentive-based Programs (2012 to 2013)	Enrollment in Time-based Programs (2013)	Percent Change in Time-based Programs (2012 to 2013)
Alaska	27	0.0%	2,468	1.00%	43	13.00%
FRCC	1,924	-41.8%	1,554,830	17.00%	16,203	-40.00%
Hawaii	35	-16.8%	36,332	-1.00%	365	13.00%
MRO	4,264	-23.4%	1,248,723	57.00%	108,527	32.00%
NPCC	467	-23.0%	62,631	15.00%	258,426	-12.00%
RFC	5,362	-8.1%	1,852,985	33.00%	1,977,536	356.00%
SERC	8,254	36.5%	1,084,449	52.00%	236,662	31.00%
SPP	1,594	20.5%	193,507	111.00%	1,143,774	1756.00%
TRE	459	-4.3%	138,613	26.00%	968	60.00%
WECC	4,681	-11.2%	3,002,607	240.00%	2,146,548	-17.00%
Total	27,095	-4.9%	9,187,350	69.00%	5,977,281	60.00%

SOURCE: North American Electric Reliability Corporation (NERC), n.d. *NERC Regions*. Available at: http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Regions_Color.jpg (accessed 2/4/15) and FERC. December 2015. *Assessment of Demand Response and Advanced Metering*. Available at: <http://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf> (accessed 2/4/15)

Scope of the Demand Response Survey

The MPSC staff Demand Response Team conducted a survey of direct load control (DLC), time-varying rate, and other DR-related tariffs offered by several regulated utilities across North America. Because 90 percent of Michigan’s electricity market is traditionally regulated, this review focuses on similar jurisdiction and regulated utilities. The sheer number of utilities and DR rates offered makes a comprehensive study impractical; instead, this survey focuses on select utilities DR rate offers. The utilities reviewed in this study are listed below in Exhibit 2. This survey provides a broad look at *common* industry practices for DR, and was conducted primarily through analysis of each utility’s public utility commission-approved tariff sheets. Many of the programs included in this study, and DR practices in general, are relatively new, and more time will be needed for *best* practices to emerge. The intent of the survey is to catalogue and present for discussion the many ways utilities offer customers the opportunity to reduce their peak demand, and how experiences from these programs can be used to develop better DR programs in Michigan.

EXHIBIT 2. Utilities Surveyed

Jurisdiction	Utility	Jurisdiction	Utility
Arizona	Salt River Project	Maryland	Potomac Electric Power Company (Pepco)
Arkansas	Oklahoma Gas and Electric* (OG&E)	Minnesota	Xcel Energy
California	Pacific Gas and Electric Company (PG&E)	North Carolina	Dominion Virginia Power
California	Sacramento Municipal Utility District* (SMUD)	Oklahoma	Oklahoma Gas and Electric* (OGE)
California	San Diego Gas and Electric (SDG&E)	Oklahoma	Public Service Company of Oklahoma
Florida	Duke Energy	Ontario	Ontario Energy Board (OEB)
Florida	Florida Power and Light (FPL)	Oregon	Pacific Power
Florida	Gulf Power	Tennessee	Kingsport Power Company
Georgia	Georgia Power	Virginia	Appalachian Power
Indiana	Indiana Michigan Power (I&M)	Virginia	Dominion Virginia Power
Illinois	Commonwealth Edison Company	West Virginia	Appalachian Power
Kentucky	Kentucky Power	Wisconsin	Wisconsin Electric Power Company
Maryland	Delmarva Power	Wisconsin	Wisconsin Public Service Corporation
Maryland	Baltimore Gas and Electric (BGE)		

SOURCE: MPSC Staff

* Participated in the U.S. Department of Energy's (DOE) Smart Grid Investment Grant Program (SGIGP) to conduct consumer behavior studies (CMS).

MPSC Staff Demand Response Survey Findings

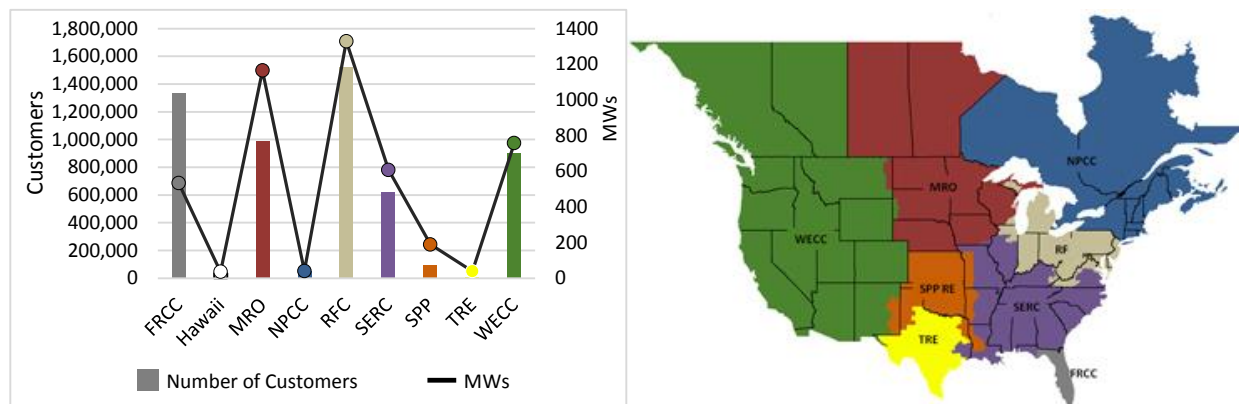
Demand response programs involve two types of mechanisms: 1) sending quantity (curtailment) signals to customers (direct load control programs, or DLC); and 2) sending price signals to customers to alter their consumption habits (time-varying rates). While these mechanisms have different characteristics and capabilities, each is a valuable tool for utilities to cost-effectively meet their system's energy needs, as discussed below.

Direct Load Control

DLC programs are relatively common and some have been in place for more than 20 years (E Source 2012). As of 2012, more than 200 utilities across the country offered some type of DLC program for residential customers (FERC December 2012). DLC programs allow a utility to directly alter a customer's energy consumption, generally through a remote control device installed on a customer's appliance, when energy demand is highest. By reducing the amount of energy certain customers can consume at these times, utilities avoid dispatching more costly generation or experiencing negative impacts to the transmission and distribution grid. This results in overall savings for the utility and an incentive payment for participating customers in most utilities' DLC programs. The majority of those programs are for residential central air conditioning switches, but some offer a credit for each controlled electric appliance the customer registers with the utility. Electric water heaters and pool pumps are also commonly incentivized with fixed-bill credits, and cycled in a similar manner. With air conditioning, when the utility expects a high peak-load day due to very warm weather forecasts, they will notify the customer in advance of the impending event. When energy demand peaks, the utility will send a signal to a customer's air conditioner (or other appliance) that causes it to operate for half the time it normally would.¹ Exhibit 3 below provides an overview of the amount of customers enrolled in utility DLC programs as well as DLCs' contributions to peak demand. More details about utilities' specific DR programs are available in Appendix A of this report.

¹ Referred to as air conditioning cycling. Air condition cycling can occur at different levels: 50 percent cycling means the unit would only run half of the time, 100 percent cycling would mean the unit would cease operation for the entire interruption period.

EXHIBIT 3. Number of Direct Load Control Program Customers and Peak Demand Contribution by NERC Region (2011)



SOURCE: North American Electric Reliability Corporation (NERC), n.d. *NERC Regions*. Available at: http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Regions_Color.jpg (accessed 2/4/15) and FERC. December 2012. *Assessment of Demand Response and Advanced Metering*. Available at: <http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp> (accessed 2/4/15)

CUSTOMER INCENTIVE LEVELS

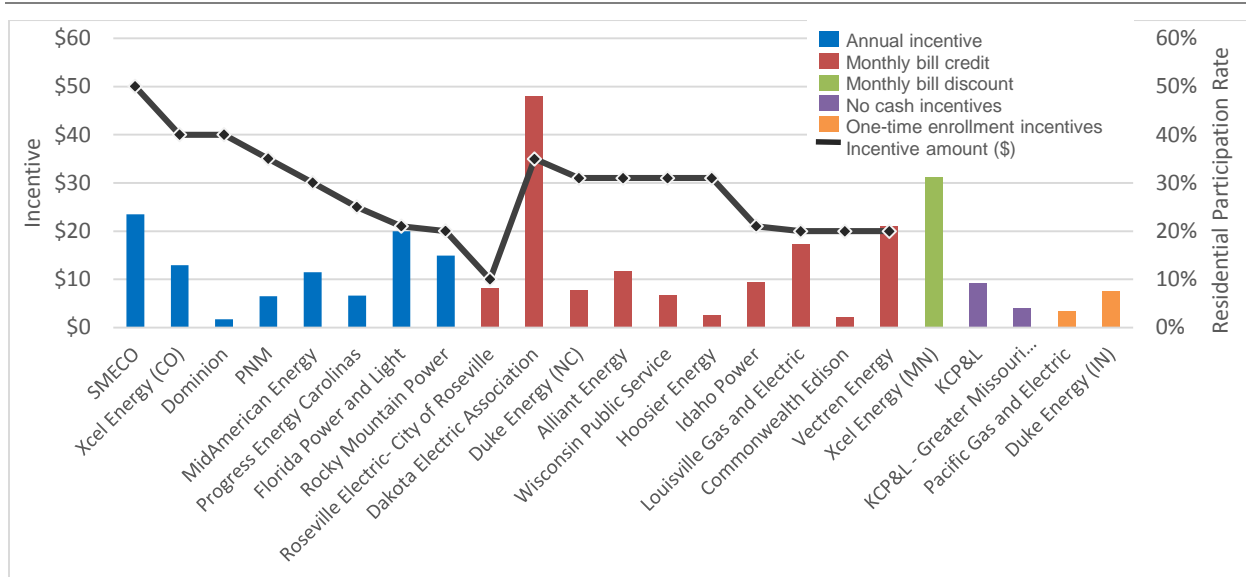
According to the MPSC’s demand response survey, a common feature among DLC programs is that customers have a choice between level of service interruption they will accept and amount of an incentive they receive. Typically these are directly variable—the more interruption a customer will tolerate, the higher the incentive they receive. Baltimore Gas and Electric Company allows customers to select from three different interruption levels: 50 percent, 75 percent, and 100 percent air conditioning cycling. The more interruption a customer is willing to tolerate corresponds with higher annual incentives \$50, \$75, and \$100 respectively. Other utilities, including Florida Power and Light and Commonwealth Edison Company, also offer different cycling options for customers with corresponding incentives. Residential DLC programs with cycling options and fixed monthly bill credits offer a simple and understandable method for customers to reduce their addition to peak load without tying the benefit to abstract concepts like kW demand charges or kWh shifting. Utility marketing and anecdotal evidence suggests that customers rarely notice a change in comfort level with appliance cycling. Many utilities’ DLC tariffs allow customers to opt-out of a certain number of events.

There were several different approaches to customer compensation identified in MPSC staff’s survey. Most common were annual or monthly bill credits for customer participation in DLC programs. However, staff identified other approaches for customer compensation, such as credits for each enrolled kilowatt and per-event credits. Public Service Company of Oklahoma provides a \$2.50 credit for each interruption event in which the customer participated. Unlike the fixed-bill credit previously described, this variable bill credit does not provide a high level of certainty for the customer in their bill credit amount, but instead keeps DLC program costs lower in years with mild summers.

COMPENSATION’S IMPACT ON PARTICIPATION

Customer compensation for DLC programs differs from utility to utility. An earlier survey of DLC programs, referenced by Public Sector Consultants, compares four common incentive structures for customer participation, including monthly bill credits, monthly bill discounts, annual incentives, one-time enrollment incentives, and no-cash incentives. It would be reasonable to expect that the greater the incentive offered by utilities, the larger participation rates would be. Of the 23 utilities surveyed in 2012, incentives varied from \$50 per year to \$10 per month (E Source 2012). The results of this survey do not provide conclusive evidence that the size of customer incentives is an indicator for customer participation rates, as shown in Exhibit 4.

EXHIBIT 4. DLC Program Incentives and Participation Rates



SOURCE: E Source. 2012. *Hot or Not DLC Program Benchmarks: How Do You Compare?* Available at: http://www.slideshare.net/E_Source/direct-load-control-program-benchmarks (accessed 2/7/16)

SCHEDULE FOR INTERRUPTION

Like compensation, the time period and duration of service interruption varied from utility to utility. Many utilities offered different interruption periods during summer and winter months. For example, Florida Power and Light’s summer interruption period lasts from April to October, while Kentucky Utilities’ summer air-conditioning program runs from June through September. These interruption periods are typically aligned with demands on utility systems.

PROGRAMMABLE COMMUNICATING THERMOSTATS IN DLC PROGRAMS

Until recently, utility DLC programs have been enabled by a control switch installed on an individual appliance, but with advances in technology, utilities are now able to use programmable communicating thermostats to control household energy use. In the case of Georgia Power, some customers receive a smart or communicating thermostat—like the popular Nest Learning Thermostat—as part of a utility’s DLC offering. Even with these changes, customers generally have the ability to opt out of a small number of events every year.

Many energy efficiency programs offer a cash rebate to customers who buy programmable thermostats, but it should be noted that *programmable* thermostats are not necessarily *communicating* thermostats. The distinction between the two is that programmable thermostats are responsive to time, and communicating thermostats are responsive to price. Additionally, a programmable thermostat might be effective for a customer on a time-varying rate, but not a direct load control, critical peak price, or critical peak rebate rate, which require a signal from the utility to either the customer or their devices.

Time-Varying Rates

The use of time-varying rates has been increasingly enabled in recent years as advanced metering infrastructure (AMI) has become more common across utilities. Traditional utility rates reflect an average price for energy which is static throughout the year, but this structure does not reflect the real costs associated with producing energy and provides improper price signals to customers. AMI allows utilities to more easily monitor consumers’ energy consumption at more frequent intervals and enables them to establish a connection between a customer’s consumption and the true cost of producing the electricity required to meet demand with varying degrees of precision. This structure creates an incentive for customers to alter their consumption habits in response to varying prices. Utilities have begun to implement

different forms of time-varying rates in an effort to meet program objectives, whether that includes reducing peak demand, deferring transmission and distribution investment, or meeting state policy goals. There are several types of time-based rates in use around the country; a brief explanation is offered in the Exhibit 5.

EXHIBIT 5. Types of Time-Varying Rates

Time-Varying Rates	Definition
Time-of-use pricing (TOU)	Typically applies to usage over broad blocks of hours (e.g., on-peak=six hours for summer weekday afternoon; off-peak=all other hours in the summer months) where the price for each period is predetermined and constant.
Real-time pricing (RTP)	Pricing rates generally apply to usage on an hourly basis.
Variable-peak pricing (VPP)	A hybrid of time-of-use and real-time pricing where the different periods for pricing are defined in advance (e.g., on-peak=six hours for summer weekday afternoon; off-peak=all other hours in the summer months), but the price established for the on-peak period varies by utility and market conditions.
Critical-peak pricing (CPP)	When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified time, the price for electricity during these time periods is substantially raised. Two variants of this type of rate design exist: one where the time and duration of the price increase are predetermined when events are called and another where the time and duration of the price increase may vary based on the electric grid's need for reduced loads.
Critical-peak rebates (CPR)	When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during pre-specified time periods, the price for electricity during these time periods remains the same but the customer is refunded at a single, predetermined value for any reduction in consumption relative to what the utility deemed the customer was expected to consume.

SOURCE: U.S. Department of Energy (DOE). n.d. *Time Based Rate Programs*. Available at: https://www.smartgrid.gov/recovery_act/time_based_rate_programs.html (accessed 2/10/15)

Time-Varying Rate Practices

While time-varying rates are less diverse than DLC programs, there are some noteworthy distinctions from the rates reviewed by the MPSC staff Demand Response Team. Staff's observations focused on three elements of time-varying rate designs, including structure of peak periods, on- and off-peak price ratios, and the interaction of time-varying rates and DLC programs. In addition to staff's findings, Public Sector Consultants references the U.S. Department of Energy (DOE) Smart Grid Investment Grant (SGIG) program which partnered with ten utilities across the country to conduct consumer behavior studies (CBS). DOE's CBS program goal was to advance understanding of time-varying rates in order to improve program designs, implementation strategies, and evaluation (DOE June 2015). DOE's 2015 CBS report details the effects of prices versus rebates and the impacts of opt-in and opt-out options in time-varying rate programs.

While in many cases the results of CBS programs have showcased successes that can be used in subsequent program designs, these successes are meant to be informative rather than prescriptive. Specifics of the time-varying rates offered by CBS utilities are available in Appendix C of this report.

PEAK PERIODS

Wisconsin Electric Power (WEP), Wisconsin Public Service Corporation (WPSC), and Salt River Project allow their time-varying rate customers to choose their on-peak periods, whereas all other utilities in this survey set their own peak periods that are assumed to be unique to their respective load characteristics.

PRICE RATIOS

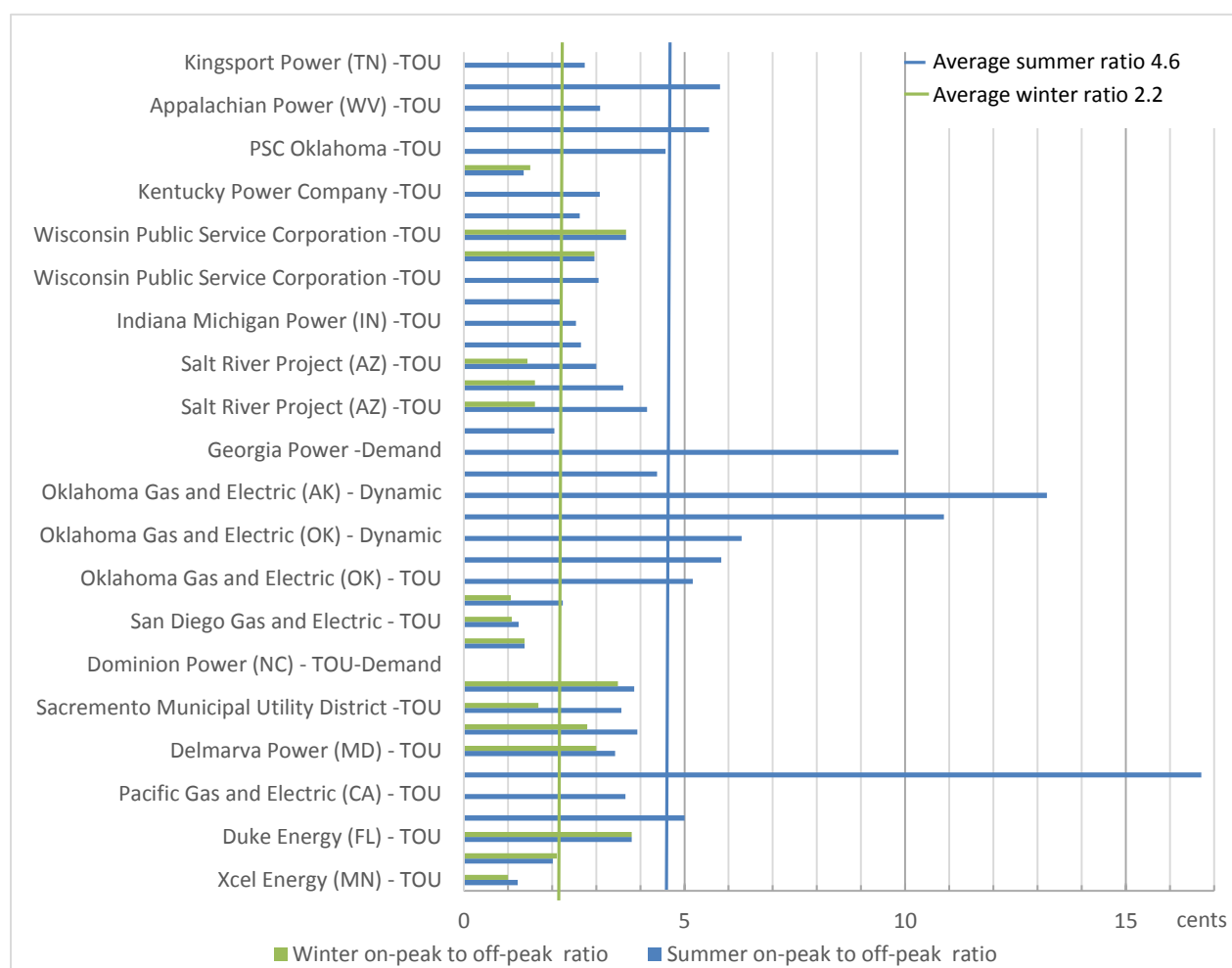
Another variable attribute to time-varying rates are the prices themselves. Among the surveyed utilities, Florida Power and Light (FPL) had the highest ratio of on-peak to off-peak summer prices. FPL's summer time-varying rate has an on-peak charge of 13.5¢ per kWh and an off-peak of 0.81¢ per kWh—a ratio of

16.7.² Minnesota's Xcel Energy registered the lowest on/off ratio of 1.22 for their summer time-varying rates.

While nearly all utility time-varying rate prices are predetermined based on time of day, Oklahoma Gas and Electric allow their time-varying rate to fluctuate to specified levels based on a "day-ahead rate" that is calculated as part of an industrial rate offering. While this survey does not cover many commercial or industrial rates, as they tend to be much more mature and well established, it is interesting to note that Rocky Mountain Power provides large customers with access to their Energy Exchange program which offers changing price signals for which customers can choose to curtail their load.

Utilities' on/off peak ratios are shown in Exhibit 6. Unfortunately, time did not allow for research into the utilities' rate case that established their time-varying prices to discover the reasoning for each on/off ratio. However, should such a research effort be conducted, the likely result will be similar to the experience in setting Michigan utilities' time-varying rates: on- and off-peak prices are designed to recover their assigned portion of the revenue requirement while keeping the previously established on/off ratio.

EXHIBIT 6. On- and Off-Peak Price Ratios



SOURCE: MPSC Staff Demand Response Team Survey

²One way to characterize the price differential of time-varying rates is to calculate the ratio of the on peak price or rebate level to the traditional electric rate faced by the control group. If this price ratio is greater than one, customers have financial incentives to change behavior and reduce peak demand during events (Cappers June 2015).

EFFECTS OF OPT-IN VERSUS OPT-OUT

One of DOE's major findings from its CBS report relates to the effects of opt-in and opt-out provisions in time-varying rates. DOE found, "Results from the CBS utilities show that enrollment rates were much higher and peak demand reductions were generally lower under opt-out recruitment approaches, but that retention rates were about the same for both. ***Because of these results, there are overall benefit-cost advantages to using opt-out approaches over opt-in.*** More analysis and further studies may be needed to demonstrate to regulators and consumer advocates that these results can be replicated" (DOE December 2015 emphasis added).

PRICES VERSUS REBATES

CBS utility practices also provided insight into how customers interact with prices and rebates in time-varying rates. According to DOE, behavioral science theory suggests people's "strong preference is almost always to avoid the loss rather than to acquire the gain. When applied to electricity time-based rates, customers are expected to be more likely to enroll in and remain on CPR than CPP. The risk from nonperformance during critical events under CPP is greater than under CPR, and this could be a motivating factor that decreases enrollment and retention." This theory was largely upheld by utilities' experience with CPP and CPR program designs. DOE's findings report that, "retention rates were higher for CPR than for CPP, and demand reductions achieved without enabling control technology were generally higher for CPP than for CPR. However, when programmable communicating thermostats (PCTs) were available as an automated control strategy, the differences in peak demand reductions between CPP and CPR were largely eliminated" (DOE December 2015).

OTHER OBSERVATIONS

Finally, there is no uniformity regarding a time-varying rate's interaction with other DR rates, namely DLC. Maryland's three largest utilities encourage customers to participate in both DLC and time-varying rates. Appalachian Power includes an option for electric water heater DLC as part of their time-varying rate (and standard residential service rate) rather than offering the program as a separate rate schedule or rider.

Other Observations about Demand Response Programs

- ❖ Some utilities recover the cost of DR programs through a surcharge on customer bills. DR program surcharges or rate riders are usually named accordingly; however, DR costs are sometimes included in an environmental charge that also recovers costs from energy efficiency programs, as is the case in Florida. When DR costs are not separated into a surcharge they are assumed to be included in a utilities' base rates.
- ❖ One common requirement of nearly all the DR rates and programs reviewed in this survey is the matter of contract length. The most common minimum commitment a customer must make for participation in DR rates is one year. Presumably, this is to prevent a customer from switching to a DR rate only when it is advantageous to them, such as taking time-varying service only in winter months when most hours are priced at off-peak rates and critical events are rarely announced. Also because, the incentive for DR programs is based on the value of customer resources available for an entire year.
- ❖ Demand response programs are all unique, and they often do not cross state lines even within the same electric utility holding company. Duke Energy, for example, has fairly robust DR offerings in Florida, but the utility has limited offerings in its Indiana service territory. In fact, Duke does not offer a time-varying residential rate in Indiana at all. Indiana Michigan Power, however, has a DLC program and an experimental time-varying rate pilot for AMI customers in the city of South Bend.
- ❖ There has been some debate among industry analysts about whether or not to make time-varying rates obligatory for residential customers. The foundational reason for compelling the residential class to be charged time-varying rates is that 1) costs for supplying power and building a distribution system depend on time and 2) residential (and to some extent small commercial) are the only customers without a time-based charge. Large commercial and industrial customers are billed on a three-part rate that includes an explicit demand charge. Two of the utilities surveyed in this study have started such programs. Pepco automatically enrolls customers with AMI in its Dynamic Pricing-Peak Energy Savings Credit rate. This rate rewards customers with a bill credit equal to \$1. Another utility—Wisconsin Electric

Power—requires customers with annual usage in excess of 60,000 kWh (5,000 kWh per month) to take service on their time-varying rate. If that customer's usage drops below 45,000 kWh annually then they are allowed to return to the standard residential rate. This practice is gaining traction in several jurisdictions. As recently as July 2015, the California Public Utilities Commission unanimously approved a plan to require TOU rates to be the default rate for residential customers by 2019 (FERC December 2015).

Important Elements of Successful DR Programs

Following MPSC staff's review of DR programs, they identified several key elements to successful program design and implementation. They include:

- ❖ Customer education is the most important aspect of any successful program.
 - Not only does education through effective marketing enable meaningful demand reduction, it also leads to improved customer satisfaction in both the program and the utility.
- ❖ The utility must provide customers with the tools needed to achieve savings.
 - Customers are most likely to participate in order to earn a reward, so it's important to show them their measurable savings along with the necessary tools to achieve them.
 - Tools include physical hardware such as thermostats and switches, as well as reliable communication of peak events and tips on how and when to conserve energy.
 - Feedback on how much customers saved immediately following a peak event is an effective way to encourage peak demand reduction and foster positive sentiment towards the program and utility.
 - Allowing the customer to see their potential, quantifiable savings by enrolling in a DR program can lead to higher participation rates.
 - For DLC programs, a set monthly bill credit (i.e., \$4 during summer months) rather than a varying rate discount gives the customer confidence in their future savings.
 - For TOU rates, the utility should use historical customer data to calculate the potential impact of the DR program (e.g., shadow billing).
- ❖ Marketing multiple DR programs together (i.e., a DLC switch and TOU rate) can save more successfully on program costs than engaging in separate marketing campaigns.
- ❖ Allowing third-party DR program administrators provides greater variety in program design and limits the utility's exposure to program-related risks, such as marketing, hardware, and software updating costs.
- ❖ Making TOU rates the default rate for eligible customers (i.e., smart metered customers) leads to very high participation.

Appendix A. Survey of Utility Demand Response Tariffs (Excluding Time of Use Rates)

- 1. Delmarva, Pepco, BG&E***
 - a. DLC - residential customer has a choice of how often she would be willing to be interrupted, and receives annual bill credits corresponding to that choice
 - i. 50% (15 minutes per every half hour) \$40
 - ii. 75% (22.5 minutes per half hour) \$60
 - iii. 100% (30 minutes per half hour) \$80
 - b. Customers receive bill credit for either a smart thermostat or an AC switch
 - c. Customers should also sign up for the dynamic pricing (critical peak rebate) rate to take full advantage of the installed equipment (automatic for Pepco customers)
- 2. Pepco***
 - a. Dynamic Pricing - Peak Energy Savings Credit
 - i. Residential customers with AMI are automatically enrolled in this peak-time rebate rider
 - ii. Customer receives a bill credit of \$1.25 per kWh reduction from customer base line during an event
- 3. BG&E***
 - a. PeakRewards Multifamily Program - Programmable thermostats are provided to tenants who choose participation levels and receive annual bill credits
 - i. 50% (15 minutes per every half hour) \$60
 - ii. 75% (22.5 minutes per half hour) \$75
 - iii. 100% (30 minutes per half hour) \$100
- 4. Florida Power and Light***
 - a. Allows customer to make a lump sum payment of \$259.68 to cover TOU metering costs in exchange for a lower monthly customer charge
 - b. TOU Rate is a rider attached to the standard residential rate, so the on and off-peak prices in the TOU tariff modify the standard tariff.
 - c. DLC - Customers get bill credits depending on what appliances they allow to be interrupted and the duration of those interruptions.
 - i. Conventional electric water heater \$1.50, year round
 - ii. Central electric air conditioning (option C) \$3, April-October
 - iii. Central electric air conditioning (option S) \$9, April-October
 - iv. Swimming pool pump \$3, year-round
 - v. Central electric space heating (option C) \$2, November-March
 - vi. Central electric space heating (option S) \$2, November-March
- 5. Dominion Virginia Power**
 - a. Winter and summer on-peak demand charges (as well as a TOU rate)
- 6. Oklahoma Gas and Electric***
 - a. In addition to standard TOU and CPP rates, they offer a variable peak pricing rate
 - i. On-peak price is 2.7¢, if day ahead price is less than 1.1
 - ii. On-peak price is 6.8¢, if day ahead price is between 1.1 and 3.1
 - iii. On-peak price is 14¢, if day ahead price is between 3.1 and 17
 - iv. On-peak price is 38¢, if day ahead price is greater than 17
 - b. The on-peak rate is communicated to the customer the day before
 - c. Basically, it's a predetermined rate scale with limited upside risk to the customer, but higher low-end prices
- 7. Duke Energy Florida***
 - a. Just like Florida Power and Light, offers monthly credits per interruptible device (and amount of interruption)

* - Utility includes DR program costs in a special surcharge

- b. Offers a winter only DLC rate for customers using >600kWh per month who have both an electric water heater and central electric heating to be interrupted. Monthly credit of \$11.50
- 8. Kentucky Utilities***
- a. Like Florida P&L, gives monthly bill credits for participating interruptible devices (currently has over 165k participating customers)
 - i. \$5 monthly credit for each central air conditioner for June-Sept
 - ii. \$2 monthly credit for each electric water heater or pool pump for June-Sept
 - b. Offers DLC program to multi-family complexes too
 - i. Monthly credits of \$2 for the customer and \$2 for the property owner
- 9. Rocky Mountain Power***
- a. Cool Keeper Program - Standard residential DLC program with AC switches
 - i. Customer gets annual \$20 bill credit after the cooling season (prorated if the customer signs up *during* the cooling season)
 - b. Energy Exchange (available in California, Idaho, Oregon, Utah, Washington, and Wyoming)
 - i. For customers with >1MW of connected load
 - ii. Company posts a price (Market Price Signal) on the Energy Exchange site for each hour that we need energy use reduction. Enrolled customers are notified when there is a price posting available for their consideration.
 - iii. Customers evaluate the posted prices and decide if it's advantageous to pledge an energy reduction.
 - iv. Use meter and a typical usage baseline usage to calculate the actual reduction in energy use. Utility issues payment for curtailment delivered under the program rules within 45 days.
- 10. Georgia Power***
- a. Smart Usage Rate
 - i. Residential demand charge rate
 - ii. Gives customers a free Nest thermostat
- 11. Commonwealth Edison***
- a. Central AC Cycling - Customers are given an option of 50% cycling for a \$20 annual bill credit or 100% for a \$40 credit (both credits are applied monthly through the summer).
- 12. Salt River Project**
- a. EZ-3 Rate- Standard TOU rate offering, but customer chooses on-peak hours of either 3-6pm or 4-7pm
 - b. Rates have shoulder months instead of shoulder hours (i.e. no mid-peak prices, but different higher summer prices for July-Aug than for May-June and Sept-Oct)
- 13. Indiana Michigan Power**
- a. Standard residential AC DLC program. 50% cycling with an \$8 monthly rebate (\$40 annually)
- 14. Wisconsin Public Service**
- a. Cool Credits DLC - Switch-based AC and electric water heater cycling program
 - b. Customers are given a choice between:
 - i. Full interruption of their AC for an \$8 monthly bill credit during cooling season (up to 8 hours)
 - ii. 66% maximum AC cycling option for no bill credit
 - iii. full interruption (up to 8 hours) of their electric water heater for a \$2 monthly credit year-round
 - c. All customer air conditioning units or water heaters must be interruptible to qualify, but bill credits do not apply per device.
- 15. Public Service Company of Oklahoma**
- a. DLC Tariff - Utility controls residential AC unit through an approved communicating Wi-Fi enabled thermostat
 - i. Customer receives \$2.50 bill credit for each event signal in which they participate
 - ii. Non-emergency event have a 5 hour maximum
- 16. Appalachian Power Company***
- a. Load Management Water Heating Provision - This provision is not a separate rate, but an addition to the standard residential service tariff
 - i. Customers who install company-approved load management water heating systems which consume energy primarily during off-peak hours are charged 5.155¢ per kWh for the last 250 kWh of monthly usage.

- ii. Customer must be bill the standard rate for the first 200 kWh
- iii. The result is a maximum discount of \$12.70 per month (if the customer uses precisely 450 kWh), a minimum of \$9.68 (the standard rate is a declining block), and a very messy looking bill.
- b. The company no longer offers this rate in its Virginia service territory. The Virginia tariff does not include a separate DR cost surcharge like in West Virginia
 - i. However, in Virginia the Company offers a load management provision for its general service TOU rate which grants a slight discount to the rate

17. Appalachian Power Company*

- a. Residential Peak Reduction Program - DLC program using AC switches with 50% cycling schedule
 - i. Customer may opt out of one event per year
 - ii. Customer receives \$8 bill credit per cooling season month (\$40 annually) for each controlled device

18. Kingsport Power Company

- a. Same water heating DR provision as Appalachian Power, but with a price of 2.755¢ for the last 250 kWh of use (max discount of \$3.46)
- b. This discount is also available to TOU rate customers at a price of 0.937¢ for the last 250 kWh of off-peak monthly use

Appendix B. Sample Demand Response Tariffs

M.P.S.C. No. 1 - Electric

Original Sheet No. D-XX

(Final Order Case No. U-99999)

RIDER D1.99

RESIDENTIAL DLC PROGRAM

AVAILABILITY OF SERVICE: Available on an optional basis to residential and commercial customers requesting interruptible central air conditioning service. Installations must conform to the Company's specifications. Customers must have a Company provided and installed AMI meter and central home air conditioning in working order.

HOURS OF SERVICE: 24 Hours

HOURS OF INTERRUPTION: The Company will interrupt service to controlled air conditioning units by remote switch at an interval chosen by the customer. Interruption will only occur during the on-peak period established on sheet C-99.99 unless otherwise required by the Regional Transmission Operator for emergency purposes. The Company will provide notice of a pending interruption at least 1 hour in advance. The customer may cancel interruption using a method established by the Company no more than 2 times per calendar year.

INTERRUPTION PERIOD: The interruption period will be designated by the Company and shall not last longer than 3 hours, unless otherwise required by the Regional Transmission Operator for emergency purposes.

CONTRACT TERM: The customer is required to remain on this rate for a minimum of one year, and the contract is terminable on three days' notice by either party thereafter. If the customer can no longer provide the Company with the ability to interrupt their central air conditioner for any reason, the Company may return the customer to their standard rate schedule immediately.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

OPTION 1: Half-time Cycling

Interruption schedule: 15 minutes for every 30 minutes of designated interruption period

Monthly Credit: \$4 per billing month and interruptible device June through September

OPTION 2: Full-time Cycling

Interruption schedule: Entire duration of designated interruption period

Monthly Credit: \$8 per billing month and interruptible device June through September

CRITICAL PEAK REBATE OPTION: A customer choosing option 1 or 2 of this Rider may not also receive the critical peak rebate described in Rate TOU-R Residential Time-of-Use, but may still participate in the rate.

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RATE TOU-R**RESIDENTIAL TIME-OF-USE RATE**

AVAILABILITY OF SERVICE: Available to residential customers with advanced metering infrastructure or a company approved communicating thermostat.

HOURS OF OPERATION: 24 Hours

DEFINITION OF PEAK HOURS: On-peak hours occur between 4 pm and 7 pm on weekdays (not including holidays). Mid-peak hours occur from Noon to 4 pm and 7 pm to 10 pm on weekdays (not including holidays). All remaining hours are off-peak.

CONTRACT TERM: The customer must agree to remain on this rate for one year beginning with Company acceptance of the customer on the rate.

RATE:

SERVICE CHARGE: \$7 per month per meter

POWER SUPPLY CHARGES:

On-Peak Energy: 15.29¢ per kWh

Mid-Peak Energy: 10.19¢ per kWh

Off-Peak Energy: 5.241¢ per kWh

DELIVERY CHARGES:

All-Hours Energy: 5.51¢ per kWh

CRITICAL PEAK REBATE OPTION: With notification to the customer at least 1 day in advance the Company may designate the following day's on-peak period to be a critical peak event. The customer will be credited the critical peak rebate charge of 50¢ per kWh times the difference between the customer's baseline usage (CBL) and kWh usage during the event. The customer will receive no rebate if event kWh usage exceeds CBL. The customer and Company must agree to the method of communication for critical peak event notification prior to the event.

$$\text{Rebate} = \$0.50 * (\text{kWh}^{CBL} - \text{kWh}^{EVENT})$$

A customer choosing the critical peak rebate option may not also receive the monthly credit awarded in Rider R1.99 Residential DLC, but may still participate in the rider.

CUSTOMER BASELINE CALCULATION: The customer's baseline usage (CBL) will be calculated for each hour of the critical peak event as the average of the previous 4 days corresponding daily on-peak hours. For example: the CBL for the 5 o'clock hour of a Friday critical peak event will equal to the customer's average kWh usage of the 5 o'clock hour the previous Monday through Thursday.

$$CBL_h = \frac{\sum_{i=1}^4 (\text{kWh}_{t-i})}{4} \quad 16 \geq h \geq 18$$

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CONTINUED FROM ORIGINAL SHEET NO. D-XX

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

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Appendix C. Summary of CBS Time-Based Rate Offerings

Utility		Customer	Rate Type	Off Peak (\$/kWh)	Critical Peak (\$/kWh)			
Green Mountain Power		Treatment	CPP	0.144	0.6			
		Treatment	CPR	0.148	-0.6			
		Control	Flat	0.148	0.148			
First Energy (Cleveland Electric Illuminating Company)		Treatment	CPR	0.03	-0.4			
		Control	Flat	0.03	0.3			
Marblehead Municipal Light District		Treatment	CPP	0.09	1.05			
		Control	Flat	0.143	0.143			
Utility		Customer	Rate Type	Off Peak (\$/kWh)	Mid Peak (\$/kWh)	Peak (\$/kWh)	Critical Peak (\$/kWh)	
DTE Energy		Treatment	TOU + CPP	0.04	0.07	0.12	1.00	
		Control	IBR	0.069/kWh for the first 17 kWh per day; 0.083/kWh for excess consumption over 17/kWh per day				
Utility	Customer	Rate Type	Off Peak (\$/kWh)	Variable Peak One (\$/kWh)	Variable Peak Two (\$/kWh)	Variable Peak Three (\$/kWh)	Variable Peak Four (\$/kWh)	Critical Peak (\$/kWh)
Oklahoma Gas and Electric	Treatment	TOU + CPP	0.042	0.23	0.23	0.23	0.23	0.46
	Treatment	VPP + CPP	0.045	0.045	0.045	0.113	0.23	0.46
	Control	IBR	0.084/kWh for consumption up to 1,400 kWh; 0.097/kWh for consumption beyond 1,400 kWh					
Utility	Customer	Rate Type	Peak (\$/kWh)	Critical Peak One (\$/kWh)	Tier One (\$/kWh) 0-700 kWh	Tier Two (\$/kWh) 701-1425 kWh	Tier Three (\$/kWh) 1426+ kWh	
Sacramento Municipal Utility District	Treatment	CPP	n/a	0.75	0.085	0.167	0.167	
		TOU + CPP	0.27	n/a	0.085	0.166	0.166	
		TOU + CPP	0.27	0.75	0.072	0.141	0.141	
	Control	IBR	n/a	n/a	0.102	0.183	0.183	
	Treatment EAPR	CPP	n/a	0.5	0.055	0.117	0.167	
		TOU	0.2	n/a	0.055	0.116	0.166	
		TOU + CPP	0.2	0.5	0.049	0.099	0.141	
Control EAPR	IBR	n/a	n/a	0.066	0.128	0.183		

SOURCE: U.S. Department of Energy (DOE). June 2015. *Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*. Available at: http://energy.gov/sites/prod/files/2015/06/f24/ARRA-CBS_interim_program_impact_report_June2015.pdf (accessed 2/2/15)

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