ECONOMIC POTENTIAL FOR PEAK DEMAND REDUCTION IN MICHIGAN

Prepared for Advanced Energy Economy Institute

By Demand Side Analytics, LLC & Optimal Energy, Inc.

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EXECUTIVE SUMMARY

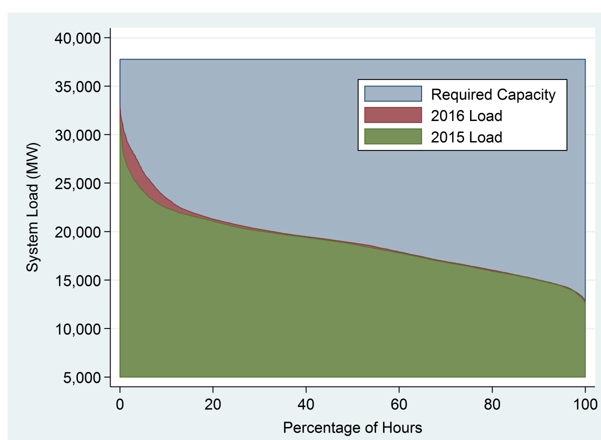
The electric power sector in Michigan is changing quickly. Policy decisions made over the coming months will shape the state's energy outlook for years to come. The retirement of coal plants, reduced competitive generation supply, increased penetration of smart meters, and changes to Midwest electricity markets will all fundamentally alter infrastructure investment strategies moving forward. Findings from this analysis commissioned by Advanced Energy Economy (AEE) Institute show that a combination of demand reduction strategies could entirely offset the projected 2,000 megawatt (MW) growth in summer peak demand in the Lower Peninsula from 2017 to 2026, avoid or defer the need to construct additional power plants, and save the state as much as $1 billion over the next decade.

To date, challenges in Michigan's power sector have been characterized mainly as potential shortfalls in generating capacity to meet projected electricity demand. The Midcontinent Independent System Operator (MISO) has identified a need for capacity imports to Michigan. The Michigan Public Service Commission's Chairman has also voiced adequacy concerns, stating "load serving entities in the Lower Peninsula do not have adequate capacity within the state to meet reserve requirements."[1]

But resource constraints on the electricity system in the Lower Peninsula are largely driven by hot weather and air conditioning loads in the summer. This means peak demand events that drive potential capacity shortfalls are predictable and good candidates for management.

We examined the potentially constrained areas of Michigan's electricity system – MISO load resource zones 2 and 7 – for the past two years. (Figure 1) The power system must be sized to meet loads in the highest hour plus a reserve margin of approximately 15%, meaning that a lot of system capacity is utilized for a very small number of peak hours. In 2015 and 2016, load exceeded 95% of the annual peak for just 76 hours. This means nearly 2,000 MW of capacity was needed to serve load in just 0.4% of hours. Demand reductions are less capital-intensive and often more economic for meeting demand during these peak hours than investment in traditional "peaker" power plants, which sit idle for most the year.

Figure 1: Load Duration Curve, Michigan MISO Zones 2 and 7, 2015-2016



[1]Palnau Judy (2016), "MPSC: State's and region's electric capacity supplies tightening," July 22, 2016, *available at* http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-389567--,00.html.

Our analysis examined the potential for various summer peak demand reduction strategies across three market scenarios that looked at different levels of avoided costs that would come from reducing demand instead of investing in additional generating capacity:

- **Low Avoided Cost:** Assumes that generation supply remains sufficient and capacity prices stay flat over the study horizon at approximately $30/kW-year. No benefit is assigned to the transmission or distribution systems.
- **Medium Avoided Cost:** Values avoided generation capacity at approximately $60/kW-year, or halfway between recent market prices and construction of a new natural gas power plant. Includes a $10/kW-year benefit each for avoided transmission and distribution capacity.
- **High Avoided Cost:** Avoided generation capacity is valued at approximately $90/kW-year, representing the cost of a new power plant as determined by the Cost of New Entry (CONE). Avoided transmission and distribution capacity valued at $20/kW-year each.

Estimates of peak demand reduction potential were developed for three separate strategies across each of the three scenarios (Table 1). Commercial and Industrial (C&I) demand response (DR) represents a program where C&I customers who are willing and able to reduce their power usage are notified the day prior to a curtailment event. For residential customers, two program designs were considered. The time-varying rate potential is based on critical peak pricing (CPP), under which electricity prices are substantially raised at times of unusually high demand. Also estimated is a program whereby the smart thermostats of participating customers are used to reduce demand when needed. Direct thermostat control and time varying rates are not mutually exclusive strategies, but do target common loads. Because the potential estimates are not completely additive, the 'Total' column excludes the connected thermostat potential.

The modeling was structured so that the avoided cost was the primary independent variable in the estimates of potential. With that as the primary input we estimated the amount of cost-effective demand response that would maximize net benefits, resulting in market estimates that correspond to strongly positive benefit-cost ratios.

The variation between estimates by scenario shows the importance of cost assumptions when comparing planning options, especially when they include expensive and long-term investments. It is worth noting that, even in the Low Avoided Cost scenario, there are savings to be had by reducing peak demand.

Table 1: 2026 Peak Demand Reduction Potential by Strategy and Avoided Cost Scenario

Avoided Cost Scenario	Non-Residential	Residential		
	Commercial and Industrial DR Potential (MW)	Connected Thermostat Control Potential (MW)	Time-Varying Rate Potential (MW)	Total*
Low	310	76	289	599
Medium	969	151	382	1,351
High	1,595	202	723	2,318

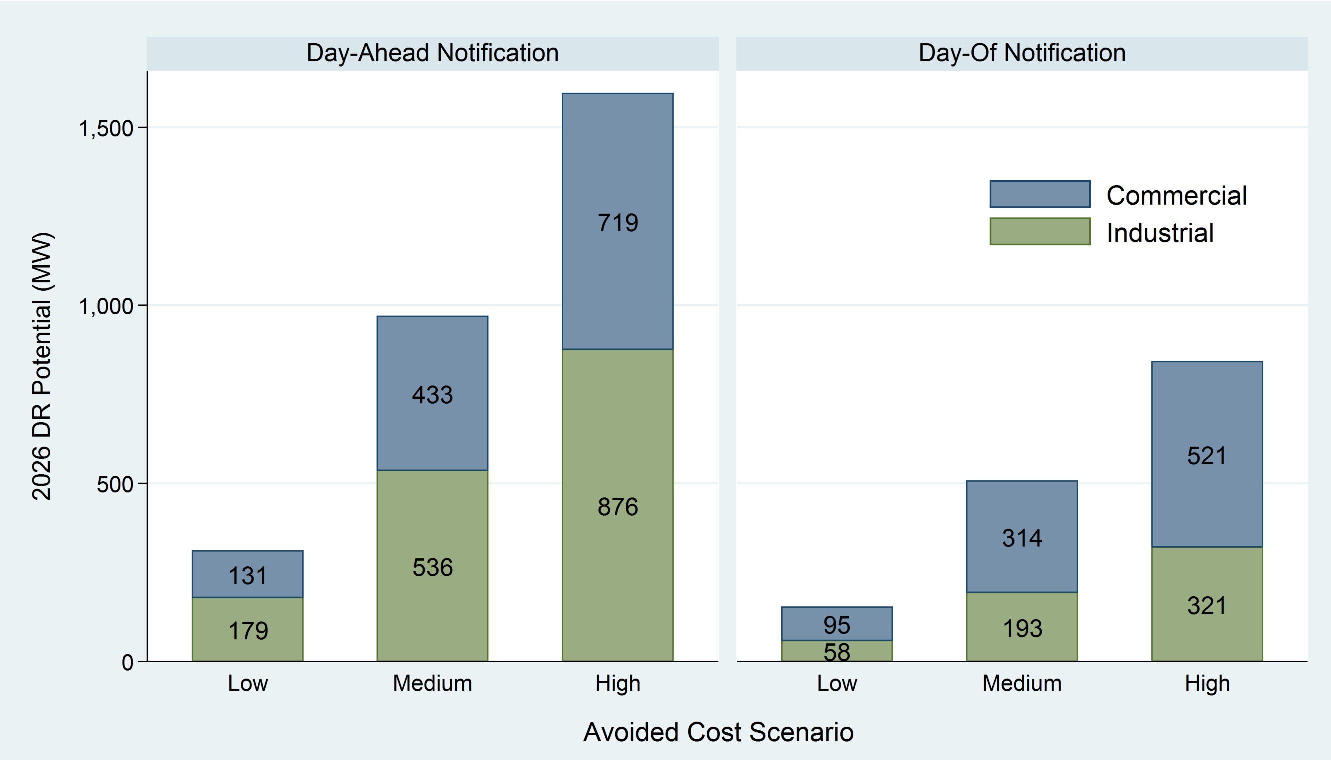
* Time-varying rate (TVR) potential estimates are for critical peak pricing. The Total column reflects C&I plus TVR only.

COMMERCIAL AND INDUSTRIAL SECTORS

Large commercial and industrial (C&I) customers represent a sizable and cost-effective demand response opportunity. Weather-driven summer peaks like Michigan's can be forecast hours or days in advance with reasonable accuracy thanks to improvements in weather forecasting technology. The amount of notification time affects the magnitude of the response, so two options were examined. A 'day-ahead' model involves identifying forecasted peak conditions and dispatching participants to shed load the following day during the expected peak hours. The 'day-of' design shortens notification time and assumes the dispatch request occurs in the morning for an afternoon peak.

The C&I DR potential is significant – in the Medium avoided cost scenario, there is C&I load curtailment potential of almost 1,000 MW in the Lower Peninsula for a day-ahead notification model with up to 40 hours of dispatch per year. (Figure 2) The opportunity is roughly halved if customer lead-time is reduced to day-of notification. The modeling approach used for this analysis assumes incentive levels set below avoided costs to optimize net benefits. In the Medium avoided cost scenario, our analysis shows a 10-year net benefit (savings) of $316 million for the day-ahead notification design and $174 million for the day-of notification design.

Figure 2: Commercial & Industrial Demand Reduction Potential by Notification Time and Avoided Cost Scenario, 2026



RESIDENTIAL SECTOR

In the residential market, existing load management programs in Michigan have relied on switches deployed by the utilities that allow them to directly control certain appliances, such as air conditioners and water heaters. Continuing to leverage these existing programs is an effective strategy, but the emergence of the "smart grid" presents new and larger opportunities. For example, rapid customer adoption of internet-connected "smart" thermostats represents a fundamental shift in the residential opportunity. Homeowners are purchasing and installing the necessary equipment, eliminating a large driver of utility program costs. Based on interviews with major thermostat vendors, we estimate there are over 70,000 connected thermostats currently installed in the Lower Peninsula. By 2026 we estimate this number will exceed 500,000 and could deliver 150 MW of peak demand reduction potential in the Medium avoided cost scenario. Coupling a 'Bring Your Own Thermostat' demand response offering with the current energy efficiency rebates of $100 from the Michigan investor-owned utilities (IOUs) could drive adoption even higher and generate additional energy savings and peak load reductions.

Beyond a "Bring Your Own Thermostat" program, the increasing deployment of advanced metering infrastructure (AMI) in Michigan enables significant opportunities to reform residential rates in a way that encourages additional electric load-shifting from peak to off-peak hours. Time-of-use rates, critical peak pricing, and/or peak time rebates all increase the economic efficiency of the system over standard flat rate pricing by using price signals to discourage excess use of electricity during peak hours. Under time-varying rate structures, total customer consumption remains the same or lower but usage patterns shift, flattening the load curve, lowering peak demand, reducing customer bills, and avoiding increases in system infrastructure costs. In this way, not only do participating customers benefit, but so do all customers, through lower overall electricity prices.

Once AMI is in place, time-varying rates (TVRs) can be rolled out at little additional cost. We have developed estimates of the residential peak demand reduction that could be provided by different TVRs by 2026. (Table 2) Opt-in rates deliver the largest reductions on a per-participant basis, but will reach significantly fewer homes than a default rate where customers can opt-out of the rate.

Table 2: 2026 Residential Peak Demand Reduction Potential by Rate Type

TVR Scenario	Average % Reduction per Participant			Total 2026 MW Reduction			2026 Reduction as % of Residential Peak Forecast		
	TOU	CPP	PTR	TOU	CPP	PTR	TOU	CPP	PTR
Opt-in, no thermostats	5.0%	15.4%	12.4%	94	289	233	1.0%	3.1%	2.5%
Opt-in thermostats	10.0%	25.9%	20.9%	138	382	308	1.5%	4.1%	3.3%
Opt-out, no thermostats	2.8%	8.6%	7.0%	221	679	548	2.4%	7.2%	5.9%
Opt-out, thermostats	5.6%	14.5%	11.7%	243	723	584	2.6%	7.7%	6.2%

TOU = Time of Use. CPP = Critical Peak Pricing. PTR = Peak Time Rebate.

The other key differentiator for time-varying rates is the inclusion of enabling technology in the form of connected thermostats. Smart devices like connected thermostats and other home automation tools allow customers to program an energy response to pricing conditions rather than taking direct action themselves. Adding enabling technology to dynamic rates has been shown to double the peak demand reduction compared to rates alone. Time-varying pricing has already proven successful in Michigan – a DTE evaluation of 1,500 customers on time-of-use rates combined with critical peak pricing shows an average peak demand reduction of about 15%.

Notably, when combined with a smart thermostat, the reduction jumped to almost 50% per home without any direct set point control. Whether through more passive approaches like rate design, or direct load control, strategies that leverage enabling technology like smart thermostats will increase DR cost-effectiveness.

The potential for peak demand reduction through residential DR is substantial. In the Medium avoided cost scenario, our model estimates a connected thermostat strategy would deliver $55 million in benefits from $34 million in costs and deliver net savings of $21 million annually over the next decade. For TVR with critical peak pricing, we estimate almost $200 million in potential benefits for a TVR over the next decade. Although implementation costs for TVRs are difficult to estimate, once the Michigan AMI network is in place, costs should represent a small fraction of the capacity benefits.

CONCLUSION

Michigan faces important decisions over the next decade as the electric grid modernizes. Our analysis shows that aggressively pursuing summer peak demand reduction is a smart and cost-effective strategy. In our Medium avoided cost scenario, a combination of residential and non-residential strategies returns approximately $900 million in benefits compared to $400 million in costs over a 10-year period. (Table 3) In the High avoided cost scenario our modeling shows $2.2B in benefits against $1B in costs over 10-year. It is important for the state to recognize demand response opportunities that are available and consider policies that capture the benefits of these resources.

Table 3: Summary of costs and benefits, 2017-2026

Low Avoided Cost Scenario			
Sector	**Costs ($M)**	**Benefits ($M)**	**Net Benefits ($M)**
C&I	$48	$79	$31
Residential Connected Thermostats	$9	$9	$0
Residential Time Varying Rates*	$40	$62	$22
Total**	**$88**	**$141**	**$53**
Medium Avoided Cost Scenario			
Sector	**Costs ($M)**	**Benefits ($M)**	**Net Benefits ($M)**
C&I	$371	$693	$322
Residential Connected Thermostats	$34	$55	$21
Residential Time Varying Rates*	$50	$189	$139
Total**	**$421**	**$882**	**$461**
High Avoided Cost Scenario			
Sector	**Costs ($M)**	**Benefits ($M)**	**Net Benefits ($M)**
C&I	$978	$1,875	$897
Residential Connected Thermostats	$64	$123	$59
Residential Time Varying Rates*	$60	$318	$258
Total**	**$1,038**	**$2,193**	**$1,155**

* Residential TVR potential based on Critical Peak Pricing Option.

** The Total column reflects C&I plus TVR only.

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SECTION 1 INTRODUCTION

There are a series of market forces and policy considerations at play that will reshape the electric power sector power in Michigan for the 21st century. As many as 25 aging coal-fired power plants will be retired in the state between 2010 and 2025. These retirements will significantly reduce emissions for the state, but could also potentially cause a shortage of generating capacity to meet demand on hot summer days. A recent energy infrastructure report for the Michigan Pub2lic Service Commission (MPSC) stated that "*Michigan's looming potential capacity shortfall could create challenges during periods of peak demand in 2018*". [2] The MPSC has also expressed concerns about whether regional capacity imports will be sufficient to meet resource adequacy needs. Projections from the Midwest Independent System Operator (MISO) show a capacity shortfall of 300 MW in the Lower Peninsula during the summer of 2018, with the number climbing to 600 MW by 2021. This is a relatively new situation for Michigan and the Midwest in general, which has typically constructed its power systems with wide reserve margins.

There are several potential strategies to maintain resource requirements in the Lower Peninsula. Capacity imports from load zones in other MISO states can be used to balance resources. However, with policies like SB 437 (Electricity Reliability Act), Michigan has been moving away from competitive supply and towards a "re-regulated" model where the Michigan investor-owned utilities (IOUs) build, or otherwise secure, the resources to meet the load in their service territory. Construction of new generation in the form of renewables or combined-cycle gas plants are often the preferred approach of IOUs because of the rate of return the assets provide shareholders. However, analysis by Advanced Energy Economy (AEE) Institute and its research partners indicates that strategic demand reductions can be a more cost-effective alternative to securing Michigan's energy requirements. Recently passed legislation also creates an opportunity for IOUs to earn a rate of return on DR investments like traditional generation plants. With a resource requirement of over 20 gigawatts (GW), the Lower Peninsula's generation capacity costs at current MISO clearing prices of \$25/kW-year will exceed \$500 million annually. With supply exiting the market, prices will likely increase, causing generation capacity costs to increase further.

Another fundamental change in the electric power sector is the broad deployment of Advanced Metering Infrastructure (AMI) – or smart meters. The AMI network gives utilities the ability to record usage in hourly or sub-hourly intervals and structure rates in a way that encourages customers to shift consumption away from peak periods and create revenue neutral reductions in peak demand. Interval meters also allow for accurate measurement and

[2]. Michigan Infrastructure Commission, *21st Century Infrastructure Commission Report*, November 30, 2016, *available at* http://miinfrastructurecommission.com/document/report.

forecasting of impacts from dispatchable demand response (DR) resources. Our research indicates that approximately half of the electric customers in the Lower Peninsula have AMI meters installed and this percentage is expected to reach nearly 100% by the end of the study horizon.

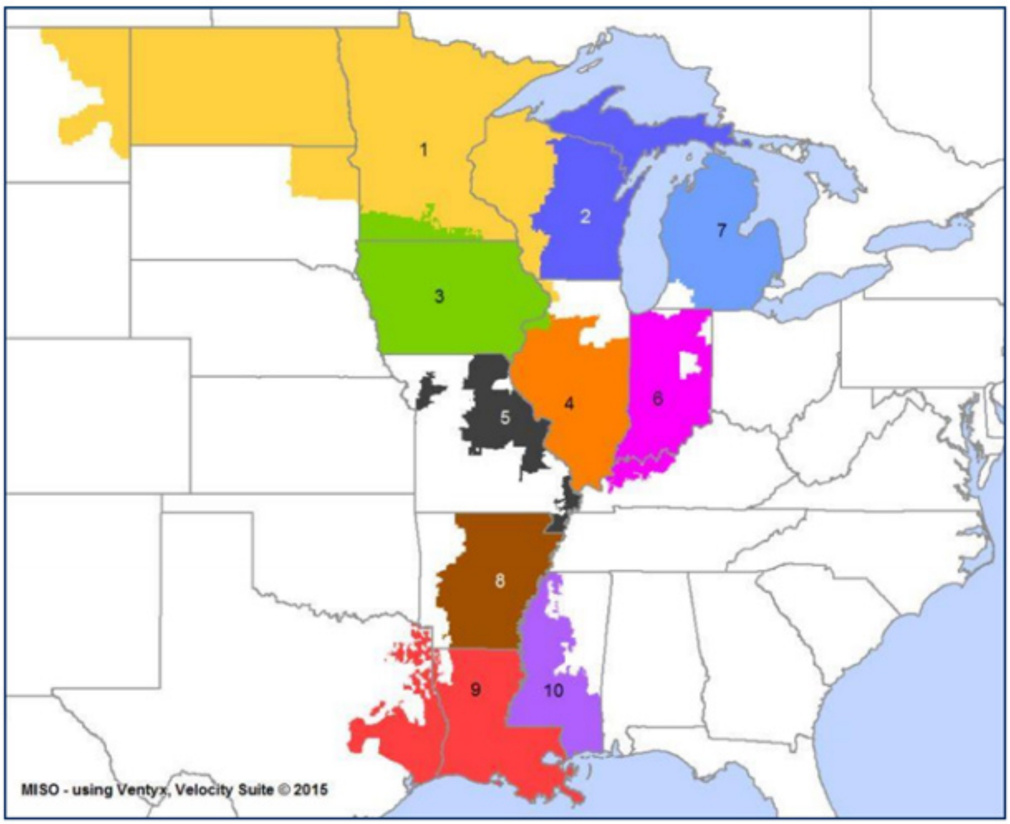
Demand response is nothing new to Michigan IOUs. DTE Electric has one of the largest residential direct load control programs in the country. Consumers Energy has over 100 MW of demand response capability in interruptible tariffs with large industrial customers. These resources have been reflected in resource adequacy planning at the MISO level, but MISO has not dispatched DR resources since 2006. The MISO Independent Market Monitor notes that this historic role of DR is likely to change as "*planning reserve margins have been decreasing and will likely continue to fall as new environmental regulations are implemented and suppliers continue to export capacity to PJM.*"[3] MISO is also revising the structure of its capacity market and has identified demand response as a strategic initiative. Considering this changing landscape and the uncertainty about dispatch and compensation of DR resources, we have chosen to model demand reduction potential across a range of market conditions. Our analysis is a high-level assessment of the magnitude of the cost-effective demand reduction opportunities. It is intended to help Michigan policymakers and utilities evaluate the feasibility of targeting strategic demand reductions as an alternative to traditional supply.

[3]. Potomac Economics, *2015 State of the Market Report for the MISO Electricity Markets*, June 2016, *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=226445.

SECTION 2 METHODOLOGY

AEE Institute and the research team chose to consider a 10-year planning horizon for this analysis because both traditional supply options and demand side alternatives take time to develop and require long-term commitments to be cost-effective. The analysis is focused on MISO Load Resource Zone 7 (LRZ7), which spans most Michigan's Lower Peninsula. (Figure 3) Load in LRZ7 is served primarily by two investor-owned utilities, DTE Electric and Consumers Energy. It does not include a small pocket in the southwest corner of the state served by Indiana Michigan Power. The data used for the analysis was taken primarily from publicly available records maintained by MISO.

Figure 3: MISO Load Resource Zone Map



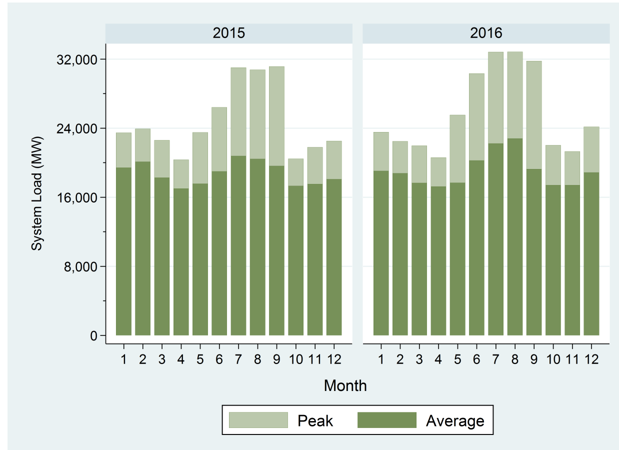
Source: MISO

2.1 LOAD CHARACTERISTICS FOR ZONE 7

Using MISO's online record database, historical hourly load data for LRZ2 and LRZ7 from 1/14/2015 (which was the earliest date available) to 12/31/2016 was analyzed. Isolating load data for LRZ7 from this database was not possible, as the hourly loads for LRZ2 and LRZ7 are not reported separately.[4] Peak load and the average hourly load for LRZ2 and LRZ7 were analyzed for each month. (Figure 4) Electric consumption is highest during the winter and summer months, implying that the load is largely driven by outdoor weather conditions. Note that the peak loads in the summer months are significantly greater than the peak loads in the off-summer months.

One measure of the efficiency of a system is load factor, which is the ratio of the system's average load and the system's peak load.[5] A high load factor is desirable because it means generation resources are being utilized most of time. For 2015, the load factor for LRZ2 and LRZ7 was 0.60. In 2016, the load factor was 0.58. During just the summer months, the load factor for each year was 0.64.

Figure 4: Peak Load and Average Hourly Load by Month



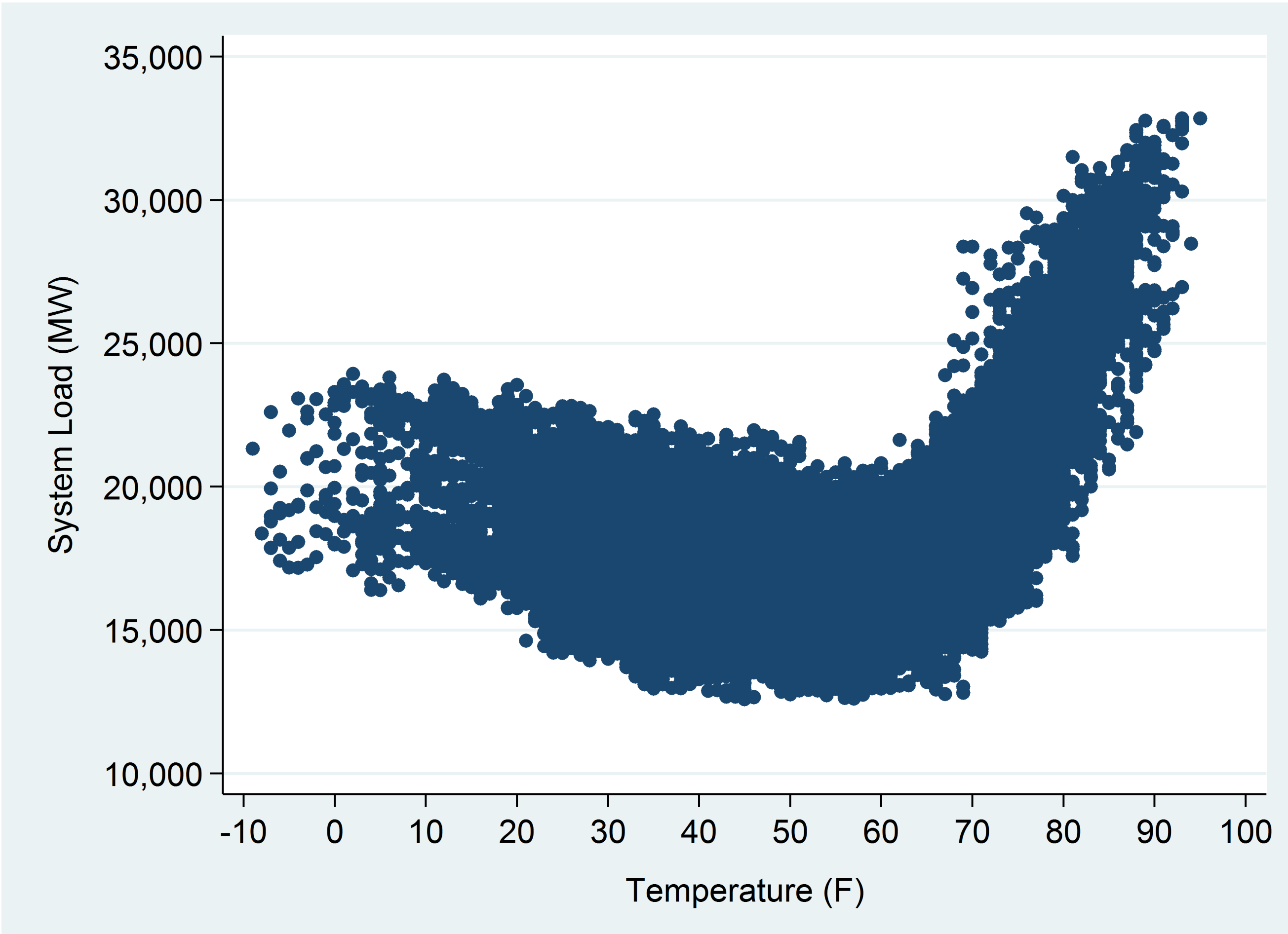
A scatterplot comparing hourly load and hourly outdoor air temperature makes the relationship between load and temperature immensely clear– weather drives the load. (Figure 5) Warm weather leads to peaking conditions and the resulting generating capacity requirements. Because weather conditions are reasonably predictable, it stands to reason that the system load is predictable too.

The Lower Peninsula is clearly a summer-peaking system. Thus, this report is focused on summer demand reduction strategies since that is when demand reduction would need to be observed to produce significant value.

[4]. Douglas J. Gotham et al., *2016 MISO Independent Load Forecast,* November 2016, *available at* https://www.misoenergy.org/Planning/Pages/IndependentLoadForecasts.aspx. . For any given hour, the load for LRZ2 and LRZ7 is reported as one single aggregate measurement. Based on LRZ2 and LRZ7 forecasts from the 2016 MISO Independent Load Forecast, LRZ7 accounts for slightly more than 60% of the combined load

[5]. Load factor = Average demand (kW) / peak demand (kW) in a specified time period

Figure 5: Hourly Load and Temperature Scatterplot



2.2 PEAK LOAD FORECAST DISAGGREGATION

The peak load forecast disaggregation draws primarily from two sources: the MISO 2016 Independent Load Forecast and GDS Associates' "Michigan Electric and Natural Gas Energy Efficiency Potential Study". [6,7] The summer non-coincident peak demand forecast for LRZ7 was drawn from the former. The MISO forecast includes projections with and without adjustments for energy efficiency, demand response, and distributed generation. The LRZ7 summer forecast without adjustments was used as the basis for this analysis. (Table 4)

[6]. Douglas J. Gotham et al., 2016 MISO Independent Load Forecast.

[7]. GDS Associates, Inc., *Michigan Electric and Natural Gas Energy Efficiency Potential Study*, November 2013, *available at* http://www.dleg.state.mi.us/mpsc/electric/workgroups/mi_ee_potential_studyw_appendices.pdf.

Table 4: LRZ7 Peak Demand Forecast

Year	Summer Forecast (MW)	Winter Forecast (MW)
2017	21,457	15,318
2018	21,868	15,612
2019	22,184	15,838
2020	22,377	15,975
2021	22,474	16,045
2022	22,629	16,155
2023	22,787	16,268
2024	23,016	16,431
2025	23,229	16,583
2026	23,427	16,725

Once the top-line forecast for the study horizon was established, the next step in the analysis was to disaggregate peak loads by customer sector (residential, commercial, or industrial) so that DR strategies could be mapped to applicable loads. To that end, we relied on the GDS Energy Efficiency Potential Study. In their report, GDS expressed the summer peak demand savings potential (by sector) in 2018 and 2023 for Michigan both in megawatts and as a percentage of the peak load forecast. Although not stated explicitly in the GDS report, dividing these two values returns the peak demand estimate. The 2018 savings potential values from the GDS report, as well as the inferred summer peak demand estimate[8] were calculated by sector. (Table 5)

[8]. The 2023 values are not shown in the table, nor are they used in our analysis, as they are approximately equal to the 2018 values.

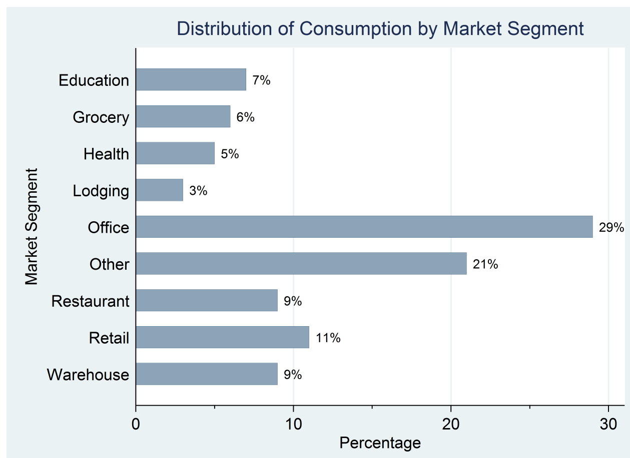
Table 5: Michigan 2018 DR Savings Potential by Sector

Sector	2018 Technical Potential (MW)	Percent of Sector Peak	2018 Summer Peak (MW)
Residential	4,274	42.7%	10,009
Commercial	5,715	53.8%	10,623
Industrial	1,790	40.6%	4,409
Total	---	---	**25,041**

Using the inferred summer peak, the distribution of the summer peak by sector can be calculated – 40% of the total peak comes from the residential sector (10,009 out of 25,041), 42.4% of the total peak comes from the commercial sector, and 17.6% of the total peak comes from the industrial sector. The values in this table apply to Michigan as a whole. Because LRZ7 makes up most of Michigan, it follows that this distribution of the peak by sector can be applied to the forecast for LRZ7.

The commercial sector can be further disaggregated by market segment. The distribution of *consumption* by market segment in 2014 was also drawn from the GDS study. (Figure 6) Using consumption as a proxy for demand is not perfect, but it is also not unreasonable. We have also assumed that the distribution of summer peak demand by commercial market segment remains consistent over the study horizon.

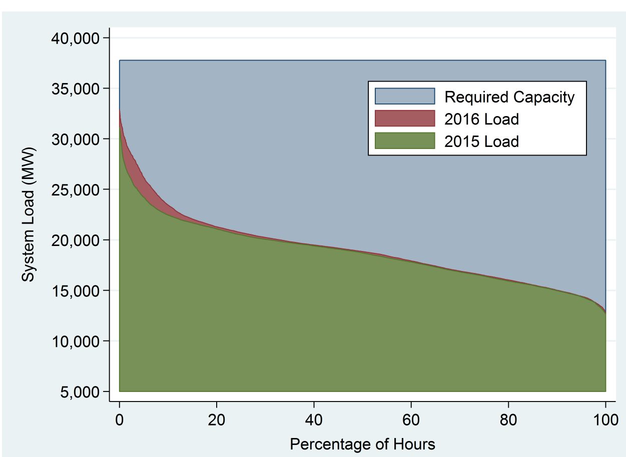
Figure 6: 2014 Estimated Distribution of Michigan Electricity Consumption by Market Segment



2.3 PROGRAM DESIGN

To estimate how much DR potential exists in LRZ7, some program design assumptions are necessary. Variables related to program design include how many events will be called, how long events will last, when will customers be notified of an upcoming event, etc. To begin constructing these assumptions, load duration curves (LDCs) for the MISO load data were examined. The LDC is constructed by sorting loads from highest to lowest and illustrates the relationship between generating capacity requirements (how the system must be sized to meet peak demand) and capacity utilization (how much of the capacity is being used in any hour). The research team examined LDCs using the 2015 and 2016 data for LRZ2 and LRZ7.[9] (Figure 7) The y-axis represents the system load and the x-axis represents the percentage of the time that the system is at or above a given load.

Figure 7: 2015 and 2016 LDCs for LRZ2 and LRZ7



[9]. Note that the 2015 data is missing the first two weeks of January.

The steep slope in the upper left hand corner of the 2015 and 2016 LDCs indicates that capacity requirements are driven by peak loading conditions in a small number of hours. Resources built to serve these peaks would be needed infrequently, which can create both technical and economic issues for power plants. Strategic demand reductions can flatten these peaks, thereby lowering the annual capacity requirements. This means examining these peaks is a useful starting place.

The 2015 peak load was 31,142 MW and the 2016 peak load was 32,846 MW. Only 33 hours in 2015 (approximately 0.4% of all hours in 2015) reached 95% of the 2015 peak load. Similarly, only 43 hours in 2016 (approximately 0.5% of all hours in 2016) reached 95% of the 2016 peak load. This disproportionate allocation of capacity to a handful of hours is compounded by the proportionate increase in reserve margin required for those hours.

Hours that reached 95% of the summer peak load were concentrated between 2:00 PM and 5:00 PM but also fell in the early afternoon and in the evening. (Table 6) Peak load hours in 2015 and 2016 were also concentrated on a limited number of days – seven in 2015 and ten in 2016. (Table 7)

Table 6: Distribution of Hours Above 95% of the Peak Load by Hour of Day

Hour of the Day (Hour Ending)	2015 Frequency	2016 Frequency
12	1	0
13	3	3
14	5	4
15	7	10
16	6	10
17	5	9
18	4	5
19	2	2
Total	33	43

Table 7: Distribution of Hours Above 95% of the Annual Peak Load by Date

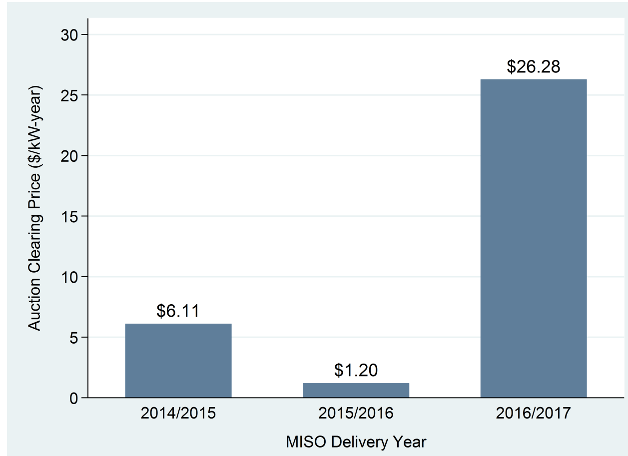
2015 Date	Number of Hours Greater than 95% of the Summer Peak	2016 Date	Number of Hours Greater than 95% of the Summer Peak
7/27	6	7/12	3
7/28	7	7/13	3
7/29	2	7/22	7
8/14	3	7/25	3
8/17	5	7/27	2
9/01	4	8/03	4
9/02	6	8/04	5
---	---	8/10	7
---	---	8/11	6
---	---	9/06	3

Assumptions about the expected frequency and duration of calls for demand reduction are critical inputs to estimates of potential. In 2015, hours where load reached 95% of the peak load were spread across just seven different days. In 2016, these hours were spread across ten days. Thus, based on our observations of system peaking conditions over the last two summers, this study assumes a DR program design with an average of eight event days and an average event length of five hours – or 40 performance hours per summer. In 2015 and 2016, this design would have impacted virtually all hours where load was within 5% of the annual peak.

2.4 AVOIDED COSTS

To model the cost-effectiveness of demand response strategies, we need to make assumptions about how to value those reductions. The primary objective of the strategies considered is to reduce the need for electric generating capacity, either by consistently lowering peak loads or allowing controlled or committed loads to satisfy generating capacity requirements. Thus, the assumption about the avoided cost of generating capacity is the primary benefit stream in the cost-effectiveness calculations and is also one of the largest sources of uncertainty. The research team examined the clearing prices for LRZ7 in MISO's last three Planning Resource Auctions. (**Figure** 8) Clearing prices have exhibited wide swings from year to year, but have generally remained low in Michigan and across MISO.

Figure 8: Three-Year History of MISO LRZ7 Clearing Prices



As supply in the region tightens, capacity clearing prices could potentially increase significantly. However, the future of environmental regulations encouraging some of the planned retirements is unclear following the presidential election. Another layer of complexity with the avoided cost of generating capacity is MISO's announcement of its intention to move to a three-year ahead forward capacity auction. Rather than attempt to forecast market conditions over a 10-year horizon, we have chosen to examine three different avoided cost scenarios (Low, Medium, and High). Instead of just using these avoided cost values to calculate cost-effectiveness for static potential estimates, our modeling approach treats these avoided costs as an independent variable that determines the estimates of DR potential. The avoided cost of generation capacity values by scenario and year for the study horizon are presented below. (Table 8) A discussion of the basis of the values follows.

Table 8: Avoided Cost of Generation Capacity Assumptions by Year and Avoided Cost Scenario

MISO Delivery Year	Low Scenario ($/kW-year)	Medium Scenario ($/kW-year)	Model Year	High Scenario ($/kW-year)
2017/2018	$26.28	$60.56	2017	$94.83
2018/2019	$26.81	$61.77	2018	$96.73
2019/2020	$27.34	$63.00	2019	$98.66
2020/2021	$27.89	$64.26	2020	$100.63
2021/2022	$28.45	$65.55	2021	$102.65
2022/2023	$29.02	$66.86	2022	$104.70
2023/2024	$29.60	$68.19	2023	$106.79
2024/2025	$30.19	$69.56	2024	$108.93
2025/2026	$30.79	$70.95	2025	$111.11
2026/2027	$31.41	$72.37	2026	$113.33

The Low avoided cost scenario assumes a starting point for the summer of 2017 equal to the LRZ7 clearing price for generation capacity in MISO's Planning Resource Auction for the 2016/2017 delivery year. This modeling decision ignores the lower clearing prices from the 2014/2015 and 2015/2016 auctions and assumes that those prices will not return because of tightening supply in the region. The High avoided cost scenario begins with value of $94.83/kW-year for summer 2017 and is based on MISO estimates of the LRZ7 *Cost of New Entry* for the 2016/2017 delivery year.[10] Cost of New Entry (CONE) is an industry planning parameter that estimates the first-year revenue needed to build a new power plant based on expected capital construction costs, and lifetime earnings and maintenance assumptions. Simply put, the High avoided cost scenario estimates potential and cost-effectiveness of demand reduction strategies assuming the alternative is to construct an infrequently used natural gas plant. The Medium avoided cost scenario uses a starting year value of $60.56, which is halfway between the Low and High scenario. We have intentionally chosen to examine outcomes across a wide range of avoided costs because potential estimates are so sensitive to this key and uncertain input. We believe the Medium case is most likely so have elected to present more detailed findings for this scenario. Avoided costs are escalated by 2% annually for each scenario over the ten-year study horizon.

The primary focus of this analysis, and the largest benefits stream assigned to the modeled reductions in peak demand, is generation capacity. However, reductions in peak demand can help avoid or defer upgrades

[10]. Mike Robinson, *Cost of New Entry PY 2016/2017*, October 2015, *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20151029/20151029%20SAWG%20Item%2004%20CONE%20PY%202016-2017.pdf.

to the transmission and distribution (T&D) system and produce real cost savings for the system. Like generation resource adequacy planning, the physical T&D infrastructure (substations, transformers, etc.) that delivers electricity to customers must be built to meet peak loading conditions. Avoided transmission benefits can take the form of delayed or deferred projects or a direct reduction in transmission payments from the IOUs to MISO.

Generating capacity requirements are driven by system-wide peaking conditions, which occur on hot summer weekday afternoons and are common across all customers. Transmission and distribution capacity requirements, on the other hand, are driven by the loading patterns on a network or circuit and can vary across the system based on the composition of customers and loads served. Local peaks may or may not be coincident with system peaks. A mostly residential substation might peak later in the evening than a substation that serves predominantly commercial loads. Because of this variability, reductions designed to shave the system peak may not always perfectly align with local peaking conditions. The other challenge with monetizing avoided T&D costs is varying growth rates. While peak demand for LRZ7 is projected to grow at approximately 1% annually over the study horizon, some areas are experiencing reductions in load and others are growing. In an area with declining loads there is effectively no T&D benefit associated with peak demand reductions. In areas where expensive capital investments driven by load growth can be delayed or avoided, the benefits of local peak demand reduction can be quite substantial. For example, Indiana Michigan Power Company recently explored targeted demand reduction to defer load growth related transformer upgrades at its Niles, Michigan substation.[11]

A detailed analysis of the location-specific avoided T&D benefits would be ideal, but is outside of the scope of this analysis. For the purposes of this analysis, we have included a single value for all load in the Lower Peninsula intended to represent a conservative blended average given the complexities discussed above.

[11]. Chris Neme & Jim Grevatt, Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments, January 2015. Available at http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

Table 9: 2017 Avoided T&D Assumptions by Avoided Cost Scenario

Avoided Cost Scenario	Avoided Transmission ($/kW-year)	Avoided Distribution ($/kW-year)	Avoided T&D ($/kW-year)
Low	$0	$0	$0
Medium	$10	$10	$20
High	$20	$20	$40

T&D = Transmission and Distribution.

The Low avoided cost scenario does not include any benefit from avoided transmission or distribution capacity. This is a very conservative outlook as the Lower Peninsula currently relies on some capacity imports, which have associated transmission charges. The Medium scenario includes a modest estimate of $10 per kW-year for both transmission and distribution and the High scenario assumes $20 per kW-yr each. One important T&D related assumption in the modeling of the opportunity for Commercial and Industrial demand response is that no distribution benefit is assigned to load reductions from Industrial customers in any of the three avoided cost scenarios. The premise behind this conservative assumption is that large industrials often take service at a primary voltage so they are mostly removed from the distribution system. Thus, it is unlikely that many IOU distribution projects could be avoided or deferred because of DR impacts from large industrial accounts.

Although the DR strategies considered are assumed to be energy neutral, the analysis does include an avoided cost of energy benefit ($/kWh). The premise of this simplifying assumption is that for each kWh of peak usage reduced, participants use an additional kWh during off-peak hours when the marginal cost is lower. Consequently, we have modeled the energy benefit as the difference between the generalized on-peak and off-peak avoided cost values. (Table 10)

Table 10: 2017 Avoided Cost of Energy Assumptions

Summer Off-Peak Energy ($/MWh)	Summer On-Peak Energy ($/MWh)	Avoided Energy Costs ($/MWh)
$30.00	$50.00	$20.00

One potential benefit stream from peak demand reductions that was not included in this analysis is wholesale price suppression. Wholesale price suppression refers to a reduction in the market clearing price for a product resulting from lower quantity demanded, which leads to a lower position on the supply curve. While the theory supporting this short-term relationship is sound, the shape of the supply curve is dynamic so providers may adjust their future auction offers to counteract price suppression effects in the long run.

2.5 COST EFFECTIVENESS

The cost-effectiveness perspective used for this study is the Utility Cost Test (UCT). This perspective, also referred to as the Program Administrator Cost Test (PACT) compares the avoided costs to the system, valued at the marginal cost, to the costs of acquiring the resource. For the demand reduction strategies examined, participant incentives are most of the cost. We have also included estimates of the fixed and variable administrative costs to operate the program. Administrative costs could include marketing expenditures, salaries of utility staff, or fees paid to a third-party implementation contractor. A discount rate of 8% was used to compare the net present value of future benefits to upfront expenditures and to express cost and benefits over the study horizon in 2017 dollars.

Establishing an analysis framework where avoided costs are an independent variable creates a situation where modelers must make decisions about the desired cost-effectiveness of the design, set corresponding incentive levels, and model potential accordingly. We could examine DR potential for a design where the costs are equal to the benefits (i.e., a UCT = 1.0). The potential for this scenario would be large because incentives could be generous, but a "break-even" program would offer no net economic advantage over supply-side alternatives. Our modeling approach seeks to maximize net benefits (benefits minus costs), rather than total demand reduction potential.

2.6 PROGRAM LEAD TIMES

The horizon for this analysis is a 10-year period from 2017 to 2026. Development and implementation of DR strategies at the scale examined in this report is a significant undertaking and it would be unrealistic to assume full-scale offerings would be ready for the summer of 2017. Program design, regulatory review, selection of contractors, and marketing and enrollment of participants all take time. With any new strategy, there can also be a benefit to a methodical rollout where lessons can be learned and adjustments made at a more manageable scale. Considering these realities, we elected to use a four-year "ramp" period to model the commercial and industrial (C&I) and residential load control opportunities. (Table 11) Like an adoption rate in estimates of "achievable" energy efficiency potential, these values act as a caliper on the magnitude of the DR opportunity to account for market barriers. When the growth factor is equal to 60% in 2018, it means that participation – along with the associated costs and benefits – is capped at 60% of the full opportunity for an established program.

Table 11: Demand Response Growth Rates

Model Year	Growth Factor
2017	30%
2018	60%
2019	90%
2020	100%

2.7 ELASTICITY OF DEMAND

The analytical approach used for C&I demand response is a 'top-down' method that uses price elasticity of demand coefficients to model DR potential under various conditions. Price elasticity of demand is the percentage change in the quantity of electricity demanded divided by the percentage change in the price (e.g., including an incentive) of DR:

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price} \quad (1)$$

For a fixed elasticity and a fixed percentage changed in price, it is possible to estimate the percentage change in the quantity of DR supplied by rearranging the terms in Equation (1):

$$\%\ change\ in\ Quantity = (Elasticity) \times (\%\ change\ in\ Price) \quad (2)$$

Coupling Equation (2) with the disaggregated peak demand forecast discussed in Section 2.2 and retail electric rates from EIA[12], it is possible to estimate how much DR potential exists in each market segment by solving Equation (3) for "DR Potential":

[12]. A 2017 retail electric rate of $0.075 per kWh was assumed for industrial customers and $0.107 per kWh was used for commercial segments. Retail rates were escalated 2% annually each year of the study horizon.

$$\% \; change \; in \; Quantity = \frac{(Summer \; peak - \; DR \; potential) - Summer \; Peak}{Summer \; Peak} * 100\% \qquad (3)$$

For more discussion on elasticity of demand as well as an example calculation, see Appendix A

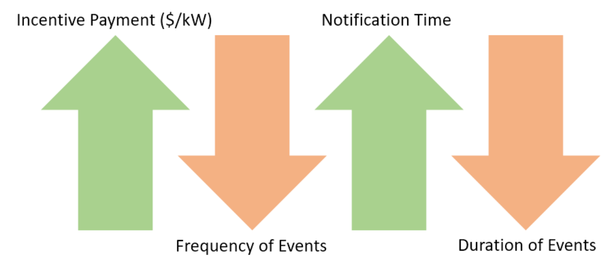
SECTION 3 COMMERCIAL AND INDUSTRIAL DEMAND RESPONSE

The largest opportunity for dispatchable demand response potential in the Lower Peninsula lies in the Commercial and Industrial sectors. Many large energy users will commit to shed load upon request in exchange for payment. This analysis models the incentive as a "reservation payment", where the program administrator pays an annual incentive to the facility to curtail when called upon. Consumers Energy's 2013 Integrated Resource Plan (IRP) indicates 122 MW of peak demand reduction potential from interruptible tariffs, and DTE may have additional interruptible potential. However, MISO has not dispatched DR resources since 2006 so the viability of these resources is somewhat untested. It is also unclear how the demand reduction potential of these interruptible accounts would change in a framework where DR resources are dispatched on a more frequent basis. As such, the methods and findings in this section examine the total opportunity in LRZ7, rather than the incremental opportunity beyond what currently sits in interruptible tariffs with the Michigan IOUs

3.1 MARKET CONDISERATIONS

The four key factors that determine demand response potential in the commercial and industrial sectors are the level of incentive payment, the frequency of events, the level of notification time, and the duration of events. (Figure 9)

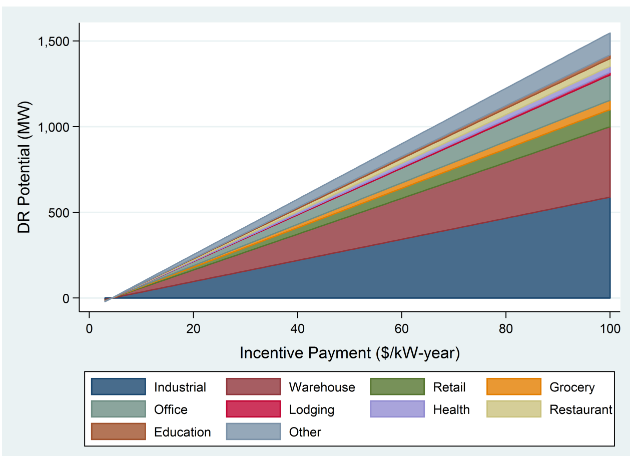
Figure 9: Primary Determinants of C&I Demand Response Potential



Including levers for each factor in the model is useful because it allows potential to be quickly examined and compared across a range of inputs, but it can produce an overwhelming number of outcomes. For this report, we have chosen to present results holding the frequency and duration of events constant at 8 days and 5 hours respectively and consider three payment levels – one each for the low, medium, and high avoided cost scenario. Results are presented for two levels of notification time. A day-ahead notification assumes participants are notified that the following afternoon will be a DR event (~24-hour notice). Day-of notification assumes that participants are notified in the morning for an afternoon event (~3-6-hour notice).

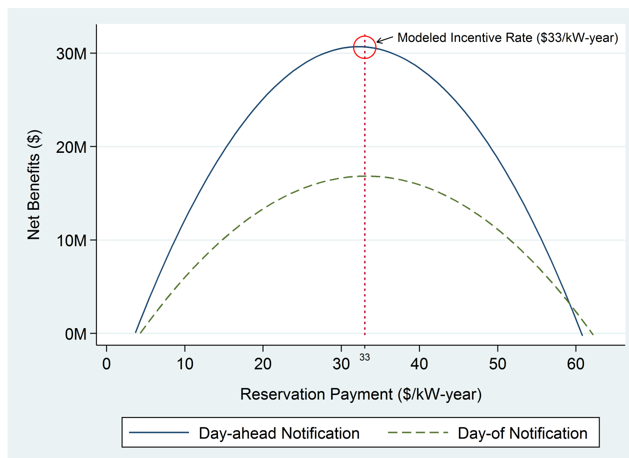
The elasticity values used for this study are linear, which leads to a linear relationship between customer incentive level and the amount of the demand response supplied. (Figure 10) There, the DR potential for a program with day-of notification is modeled (assuming 40 hours of dispatch annually). The assumed number of dispatch hours is a critical input because it determines how disruptive DR program participation will be to the primary business and drives both the decision to participate, and how much load participants wish to commit to reduce. To average 50 kW of demand reduction in a program that calls 10 hours annually, a business would need to shed a total of 500 kWh. If the program requires 50 hours per summer, the total energy reduced would equal 2,500 kWh.

Figure 10: DR Potential by Customer Segment and Incentive – Day-Of Notification



The incentive level is clearly a key driver of DR potential. For the Medium avoided cost scenario, the 2017 total avoided capacity benefit for a 1 kW reduction is approximately $70 for an industrial customer and $80 for a commercial customer. We assume a 25% markup to account for marketing, aggregator fees, and program administrator costs, so the "break-even" incentive-level in the Medium avoided cost scenario is approximately $60/kW-year. This would be the incentive level with the greatest potential, but the benefits would equal the costs (UCT = 1.0). By looping through a range of incentive levels and calculating MW potential, program costs and benefits for each, we can examine the relationship between incentive levels and net benefits. (Figure 11) For the Medium avoided cost scenario, net benefits are maximized at an incentive of $33/kW-year. This would be the most economically efficient scenario if the sole objective was to save Michigan ratepayers electricity costs and budget was not a limitation.

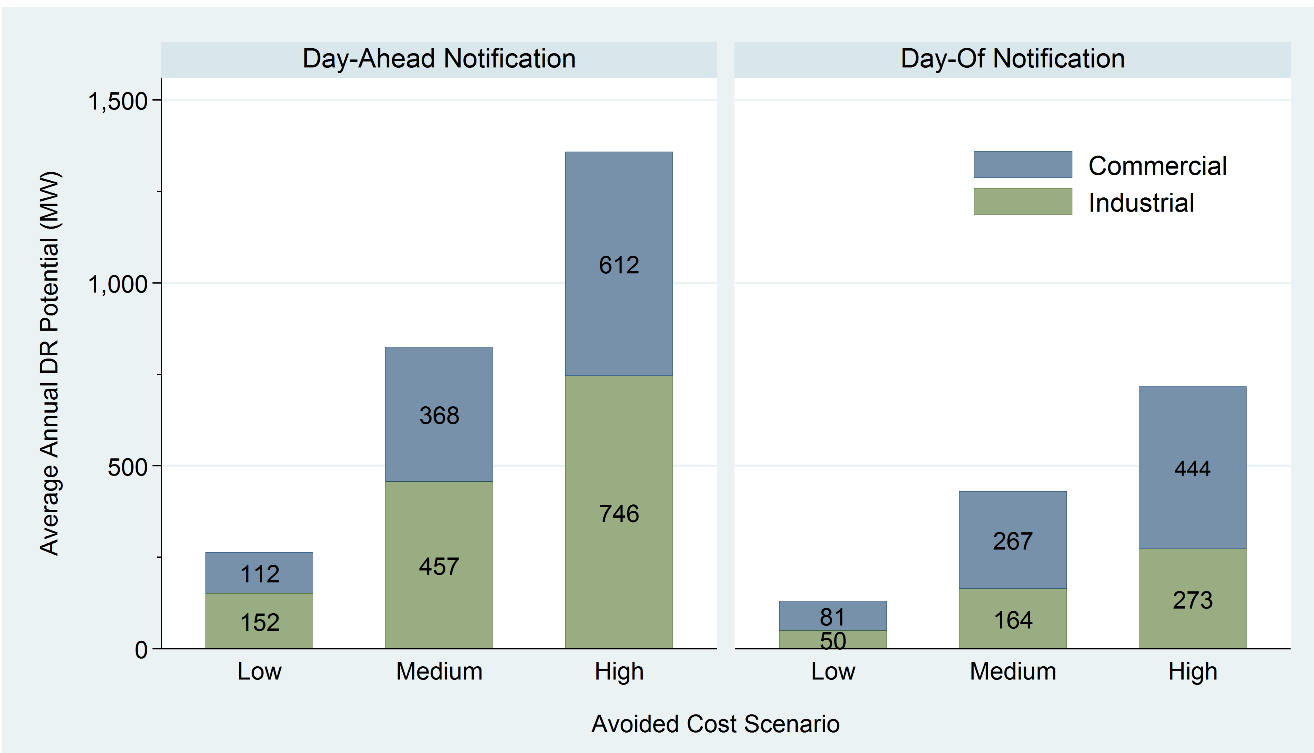
Figure 11: Relationship Between Net Benefits and Customer Incentive



3.2 RESULTS

The three avoided cost scenarios and different notification times all result in similar benefit-cost ratios with Utility Cost Test ratios ranging from 1.7 to 2.0. However, the DR potential estimates differ significantly by scenario. For each avoided cost scenario, average estimates of annual DR potential over the study horizon across are presented below. (**Figure 12**) All potential estimates are presented at the generator level.

Figure 12: DR Potential Estimates by Cost Scenario – Day-Ahead and Day-Of Notification, 10-year average 2017-2026



The 10-year average estimates of DR potential are restricted somewhat by the gradual four-year trajectory discussed in Section 2.6. The following tables isolate estimates for the final year of the study horizon (2026) once customer awareness and acceptance are assumed to have reached a saturation point. Findings are presented separately for a day-ahead notification design and a day-of notification design. (Table 12 and) Both tables assume 40 hours of DR events annually. The tables also include the peak load forecast for each segment so the relative magnitude of the estimates can be demonstrated. Figures concerning costs, benefits, and net benefits of the day-ahead and day-of notification designs follow the tables.

Table 12: 2026 Demand Reduction Potential Estimates by Avoided Cost Scenario – Day-Ahead Notification

Segment	Peak Load Forecast (MW)	DR Potential (MW) by Avoided Cost Scenario		
		Low	Medium	High
Warehouse	894	33	108	179
Retail	1,093	11	37	61
Grocery	596	6	20	33
Office	2,882	29	96	160
Lodging	298	3	10	17
Health	497	11	35	58
Restaurant	894	9	30	50
Education	696	6	21	35
Other	2,087	23	77	127
Commercial Total	9,938	131	433	719
Industrial	4,125	179	536	876
C&I Total	**14,063**	**310 (2%)**	**969 (7%)**	**1,595 (11%)**

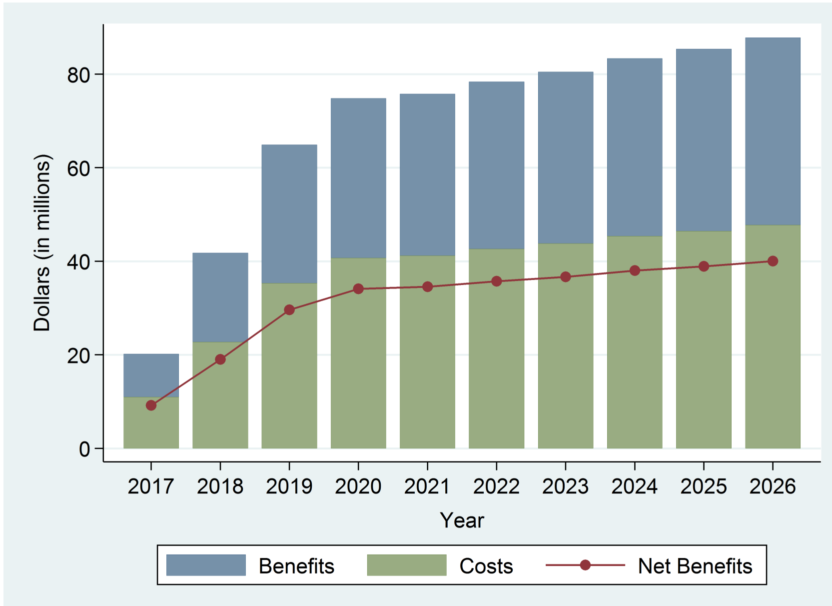
Industrial customers are the largest source of DR potential for each permutation, both in MW and percent reductions. Notice in the High avoided cost scenario, the percent reduction in peak load for industrial customers is 21.2% (876 out of 4,125). (Table 12) This speaks to the flexibility of loads in industrial facilities. With attractive incentive payments and advance notification, our modeling indicates these facilities will schedule energy-intense processes to shift large amounts of load to off peak periods even if the number of dispatch hours is relatively high.

Under the Medium avoided cost scenario, the estimated costs, benefits, and net benefits for the day-ahead notification design are shown by year below. (Figure 13) Note that the dollar amounts shown in the figure are not discounted to reflect the net present value of future investments. For example, the net benefit in 2020 is approximately $33.9 million – this value is given in 2020 dollars, not 2017 dollars. Over the 10-year study horizon, the total estimated costs, benefits, and net benefits are $377 million, $693 million, and $316 million respectively.

Table 13: 2026 Demand Reduction Potential Estimates by Avoided Cost Scenario – Day-Of Notification

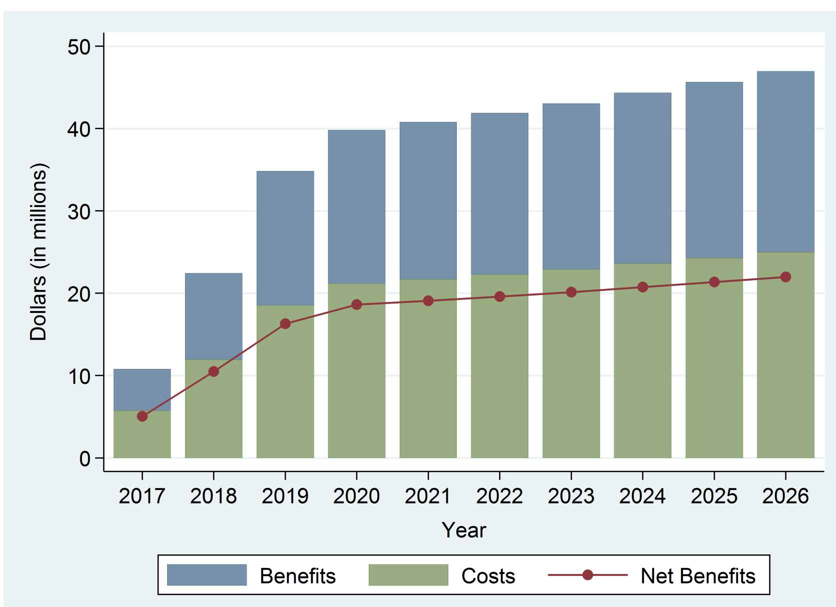
Segment	Peak Load Forecast (MW)	DR Potential (MW) by Avoided Cost Scenario		
		Low	Medium	High
Warehouse	894	41	134	223
Retail	1,093	10	33	55
Grocery	596	5	18	30
Office	2,882	15	48	80
Lodging	298	2	5	8
Health	497	4	12	19
Restaurant	894	5	15	25
Education	696	2	7	12
Other	2,087	13	42	70
Commercial Total	9,938	96	314	521
Industrial	4,125	58	193	321
C&I Total	**14,063**	**154 (1%)**	**507 (4%)**	**842 (6%)**

Figure 13: Financials for Day-Ahead Notification Design



The financials for the day-of notification design follow a similar trajectory over the study horizon. (Figure 14) Again, these values are for the Medium avoided cost scenario and the dollar amounts shown in the figure reflect the value in program year. Over the 10-year study horizon, the total estimated costs, benefits, and net benefits are $197 million, $371 million, and $174 million respectively

Figure 14: Financials for Day-Of Program Design



SECTION 4 RESIDENTIAL DEMAND RESPONSE

4.1 EXISTING INFRASTRUCTURE

DTE Electric appears to have the only large residential direct load control program in Michigan. Federal Energy Regulatory Commission (FERC) DR surveys indicate that there are approximately 220,000 customers in the CoolCurrents air conditioning program and approximately 60,000 electric water heating customers on load management switch programs.[13] This equates to approximately 200 MW of air conditioning and 25 MW of water heating control on a hot summer day. Consumers Energy has a pilot air conditioning load management program and their 2013 IRP forecasts a 41 MW program for 2016. Assuming the Consumers Energy's IRP forecast is accurate, then there are approximately 240 MW of air conditioning load management and 25 MW of water heater control for the residential class in 2016 – in total, approximately 265 MW of residential demand response available in 2016.

The existing load management programs are expected to be the most cost-effective residential demand response resource over the study horizon because the equipment and installation costs are sunk. If the ongoing participant incentive and program administrative costs are less than the capacity benefits generated, Michigan should continue to leverage these existing programs. Our analysis indicates additional installations of direct load control equipment is likely not cost-effective except in the High benefits scenario. The capacity benefits over the life of the equipment do not overcome the approximately $300 per home of upfront equipment and installation costs unless a negligible annual participation incentive is assumed.[14]

4.2 MARKET ADOPTION OF CONNECTED THERMOSTATS

There are several vendors producing and marketing internet-connected 'smart' thermostats directly to residential customers nationwide – the Nest thermostat and the Ecobee thermostat are two prominent examples. These devices are typically sold as home energy management tools that target energy savings for homeowners through occupancy detection, auxiliary heat lockout, and economizer capabilities. As of November 2016, there were an estimated 71,000 connected thermostats in the Lower Peninsula of Michigan. This estimate is based on interviews with the

13. https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

14. Demand Side Analytics review of cost data from various direct load control programs

two primary vendors in the product category and an estimate of their overall market share.

Connected thermostats represent a fundamental shift in the economics of residential demand response because customers are purchasing and installing the devices on their own, and this removes the upfront cost barrier for the utility. Other program administrators in the Midwest like ComEd and Kansas City Power and Light (KCP&L) have taken notice and developed 'Bring Your Own Thermostat' demand response programs where the utility partners with the vendor to market the load management aspect of the device to the customer. The customer can be offered a small incentive and the vendor can be paid for its cloud-based management and deployment services.

Our interviews with thermostat manufacturers indicated that the number of smart thermostats in Michigan is currently growing at approximately 25% per year. This may seem high, but the current residential market penetration of smart thermostats in Michigan is only about 1.8%. At a 25% annual growth rate, the market penetration will only be about 12% in 2026. An industry projection from Navigant Research projects an international growth rate in the product category from 1.4 million homes in 2013 to 31.9 million homes in 2020, which equals a growth rate of 56% annually.[15]

Industry experience has shown load management program enrollment increases as more resources are applied to marketing, but enrollment typically maxes out between 40% and 50%. The research team developed enrollment estimates for low, medium and high levels of marketing aggressiveness. (**Table 14**) These three levels correspond to the broader avoided cost scenarios for the study because the amount that a program administrator can pay for marketing and incentives is a function of the value of the resource.

Table 14: Assumed Customer Incentive and Enrollment Rate by Avoided Cost Scenario

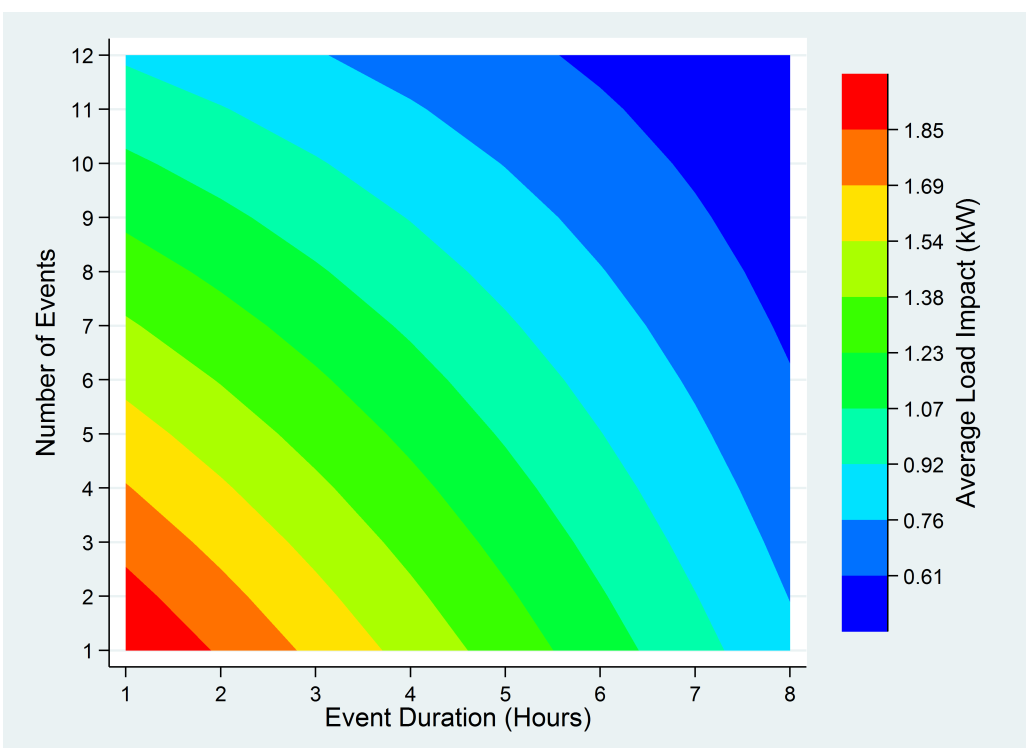
Avoided Cost Scenario	Annual Rebate per Home	Enrollment Rate
Low	$15	15%
Medium	$40	30%
High	$60	40%

[15]. Richard Martin, "Installed Base of Smart Thermostats Will Reach Nearly 32 Million by 2020," October 24, 2013, *available at* https://www.navigantresearch.com/newsroom/installed-base-of-smart-thermostats-will-reach-nearly-32-million-by-2020.

4.3 LOAD IMPACT ASSUMPTIONS

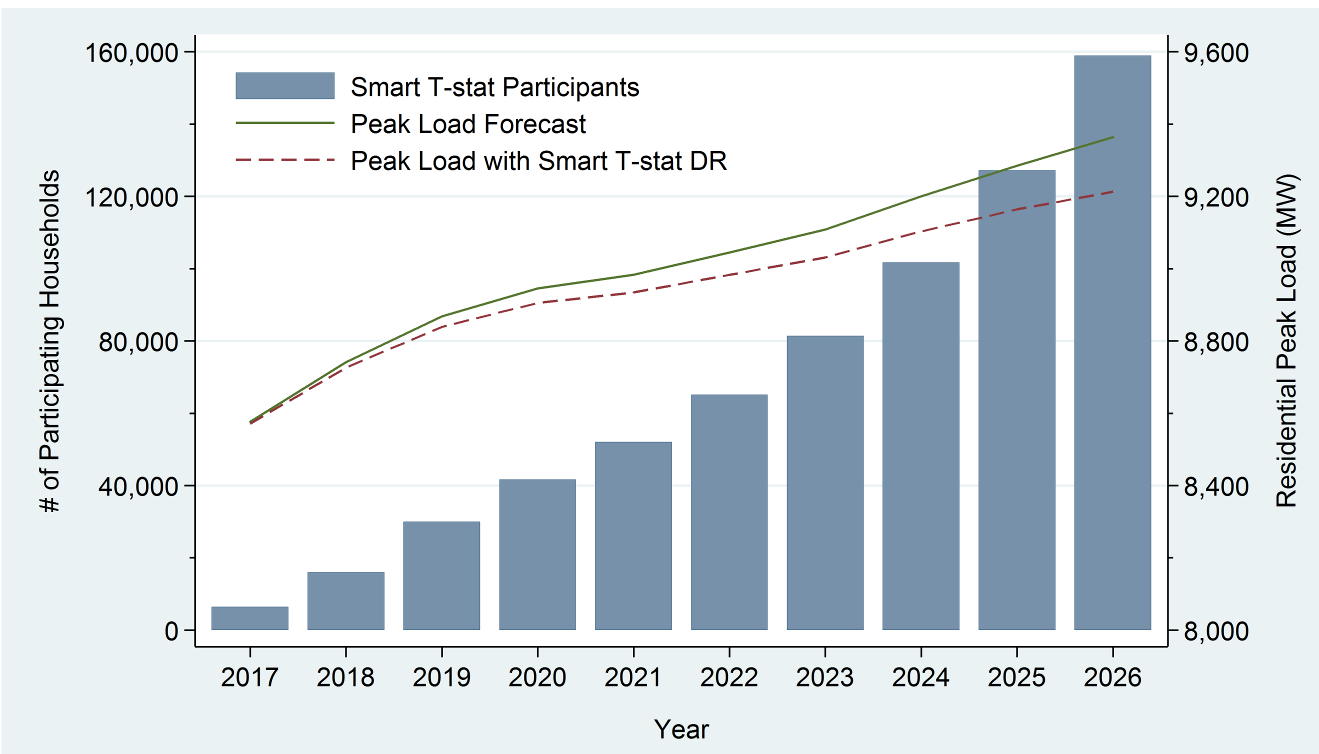
Load impacts from residential air conditioning control are influenced by the duration of events and the number of events that are called, with the average hourly load impact dropping as the number of event hours increases. The main reason average hourly load impacts decrease as the number of event hours increases is weather – when control is only initiated for a small number of hours, it will generally be on the hottest hours of the year when the air conditioning load is at its peak. As the number of hours of control increases, the amount of air conditioning load available for reduction will decrease. Thus, the average hourly load impact decreases. The second reason is related to customer acceptance and how aggressively vendors or utilities are willing to modify air conditioning usage. If control is only going to be initiated for a short period (1-2 hours) on very few days, program administrators can just eliminate the call for cooling. This means the load impact will equal the average cooling load in the home, which we estimate approaches 2 kW. It takes time for homes to warm up, so if control is brief, even aggressive control is unlikely to result in widespread participant complaints and attrition. As the frequency and duration of events increases, a less aggressive control strategy is needed. Program participation represents an agreement to forego a primary benefit of electric consumption (air conditioning on a hot day) in exchange for a financial incentive. The more frequently participants are asked to make this sacrifice, the less intense it needs to be. (Figure 15)

Figure 15: Thermostat Load Impacts vs. Event Duration and Frequency



The frequency and duration of residential demand response events are a function of the grid application the resource is intended to serve. Because of their fast response time, connected thermostats could potentially be used to provide ancillary services to the system in lots of very short events. This analysis, and the avoided cost assumptions it uses, is designed to focus on a generation capacity and peak energy application. As discussed in Section 2.3, we assumed that the event duration and number of events would both need to be large to achieve a meaningful reduction in resource requirements. The results of the Medium avoided cost scenario assuming eight events annually of five hours each (40 hours total) are presented below. (**Figure 16**) The projected population in a residential thermostat DR option grows as the market share of connected thermostats grows over the study horizon. By 2026, we estimate that a connected thermostat offering could have close to 160,000 participating households and deliver 151 MW of peak load reduction at the generator. This would represent a 1.6% reduction in the peak demand forecast for the residential sector.

Figure 16: Connected Thermostat Participation and Peak Load Reduction by Year – Medium Case



4.4 COST EFFECTIVENESS

The research team developed separate estimates of connected thermostat DR potential and cost-effectiveness by avoided cost scenario and year. (Table 15) Because of the projected growth in the product category over the study horizon, the magnitude of costs and benefits in later years are greater and drive the ten-year UCT ratio. In the Low avoided cost scenario, the modest annual customer incentive and low enrollment rate ($15 and 15% respectively) lead to a benefit stream that struggles to overcome the fixed component of program costs (assumed to be $50,000 annually) and result in a break-even outcome over the study horizon. In the Medium and High avoided cost scenarios, a connected thermostat strategy comfortably passes the Utility Cost Test from the first year on. In the High avoided cost scenario, our estimates of potential exceed 200 MW and would generate $15 million in net benefits annually ($30 million in benefits against $15 million in costs) by 2026.

Table 15: Connected Thermostat DR Potential and Benefit-Cost Ratio by Year

Program Year	DR Potential (MW)			UCT Ratio		
	Low Case	Medium Case	High Case	Low Case	Medium Case	High Case
2017	3	6	8	0.58	1.23	1.57
2018	8	15	20	0.77	1.37	1.67
2019	14	29	38	0.87	1.43	1.73
2020	20	40	53	0.91	1.48	1.78
2021	25	50	66	0.95	1.51	1.82
2022	31	62	83	0.98	1.55	1.86
2023	39	78	103	1.01	1.58	1.90
2024	48	97	129	1.04	1.62	1.94
2025	61	121	162	1.07	1.65	1.98
2026	76	151	202	1.10	1.69	2.02
10 Year UCT Ratio				**1.00**	**1.58**	**1.89**

Smart devices like connected thermostats present clear opportunities for direct load control as shown in this section. As the penetration of advanced metering infrastructure in the Lower Peninsula increases, the intersection of smart devices and the smart grid will create additional opportunities. Section SECTION 5 explores some of the opportunities associated with time-varying rates and how smart devices combined with rate design can produce significant demand reductions.

SECTION 5 TIME VARYING RATES

Residential Time-Varying Rates (TVRs) provide another important tool to flatten the load curve and reduce Michigan's peak load. Residential load demands attention as the sector has a much lower load factor in Michigan than the commercial and industrial sectors. For example, an analysis of a 2010 peak load day shows that while residential load makes up 40% of total load at 5 AM, it makes up 58% of load at 5pm, during the peak period.[16] TVRs are a particularly intriguing method for reducing the peak demand, since they can be implemented in a mostly revenue neutral manner, have minimal ongoing costs for the utility, and can bring significant other benefits by increasing the economic efficiency of how people pay for electricity.

Due to the increasing penetration of AMI, time varying rates are becoming more common throughout the world. For example:[17]

- Arizona Public Service has a long-standing time of use (TOU) rate, in which it has enrolled 51% of its customers.
- Both Ameren and ComEd have enrolled about 25,000 customers on time varying rates.
- The Massachusetts Department of Public Utilities has issued a straw proposal calling for a default critical peak pricing and time of use rate.
- In 2012, the Province of Ontario began using a TOU rate for generation charges to all customers staying with regulated supply.
- In 2014, Baltimore Gas and Electric (BG&E) ran a peak time rebate program with 867,000 customers eligible, and a 76% participation rate per event[18]

Further, utilities are now beginning to experiment with residential maximum demand charges, where in addition to total energy charges, utilities charge for the maximum demand each month. There are currently 19 U.S. utilities offering residential rates with either max demand or coincident peak charges, and more being proposed in Arizona, Kansas, Illinois, Nevada, and Oklahoma.[19]

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[16]. Michigan Public Service Commission, *Overview of Demand Response Programs in Michigan*, September 21, 2015, *available at* https://www.michigan.gov/documents/energy/MPSC_Demand_Response_Presentation_September21_References_502211_7.pdf

[17]. Ahmad Faruqui, *A Global Perspective on Time Varying Rates*, June 23, 2015, *available at* http://www.brattle.com/system/publications/pdfs/000/005/183/original/A_global_perspective_on_time-varying_rates_Faruqui_061915.pdf?1436207012.

[18]. Wayne Harbaugh, *BGE's Residential Smart Energy Rewards Program at NY REV: The Role of Time-Variant Pricing*, March 31, 2015, *available at* https://www.edf.org/sites/default/files/content/harbaugh_presentation.pdf

[19]. Ahmad Faruqui, *The Past, Present, and Future of Retail Electricity*, August 16, 2016, *available at* http://www.brattle.com/system/publications/pdfs/000/005/352/original/The_past_present_and_future_of_retail_electricity_pricing_%2808-08-2016%29.pdf?1471535256

Michigan has been taking part in this nationwide trend, with both DTE Electric and Consumer's Energy offering an opt-in dynamic peak pricing plan (DPP), which combines a time of use rate with an increased charge during peak on a maximum of 20 days. DTE Electric conducted a pilot study on its DPP plans, and found a 12.6% reduction in peak usage on critical event days, jumping to a 44.5% reduction if the resident also had a smart thermostat. DTE Electric projects that all customers will have smart meters by 2017.[20] Further, TVRs can be implemented in a revenue neutral manner, increase the economic efficiency of electricity prices, and may reduce cross-subsidization. With DTE Electric and other Michigan utilities also aggressively rolling out AMI, there are opportunities to significantly expand the number of customers on time varying rates, thus achieving significant residential demand savings in a revenue neutral manner.

5.1 GENERAL DESCRIPTION OF TVR STRATEGIES

Time varying designs charge different rates for electric usage, depending on the season and the time of day. In general, there are four main types of TVRs seen, though elements of each TVR can also be combined. For example, Michigan utilities' existing rates combine a three-tier time of use rate with a critical peak pricing charge on a limited number of days.

- **Time of Use**: Time of Use (TOU) rates offer fixed rates, depending on either time of day or time or year. For example, if a peak period on the grid is 1 pm - 7pm, all electric usage during this period may be billed at a higher rate than other usage. TOU rates are fixed by period, giving advance certainty as to what rate will be charged for each TOU period. Some utilities, including DTE Electric in Michigan, offer 3-period TOU rates, with different charges for on-peak, mid-peak, and off-peak hours.
- **Real-Time-Pricing**: Real-Time-Pricing (RTP) schemes continuously change the rate charged for electricity based on the hourly market price for electricity. Since the wholesale price for electricity continuously changes, there is no advance certainty. Real time pricing is the least explored of TVR options, although both ComEd and Ameren have residential real time pricing options in Illinois.
- **Critical Peak Pricing**: Under Critical Peak Pricing (CPP), customers pay higher peak prices during a discrete number of days when market prices are forecast to be highest. Enrollees are typically notified of these critical events a day in advance. Because this pricing occurs during a limited number of days, the difference in electric rate between the critical peak and the off-peak can be very large. Under DTE Electric's current rate design, for example, enrollees pay $1 per kWh for on-peak consumption

[20]. Karen Uhlenhuth, "Will smart meters change consumer habits? Early indicators say yes," October 10, 2013, *available at* http://midwestenergynews.com/2013/10/18/will-smart-meters-change-consumer-habits-early-indicators-say-yes/.

during up to 20 days per year, compared to an off-peak rate of $0.0422.

- **Peak Time Rebates**: In some jurisdictions, policy constraints may prevent implementation of critical peak pricing. In these cases, a similar impact can be created through peak time rebates (PTRs), where customers receive money back in exchange for lowering their electric usage compared to an estimated baseline. Unlike Critical Peak Pricing, there is no discount for non-peak usage.

An interesting variant on Peak Time Rebates is behavioral demand response (BDR). Though it lacks the financial rebate, and thus is not actually a time-varying rate, BDR relies on similar notification methods as PTR (email, text, social media) to lower household demand during peak hours. Instead of promoting the financial opportunity to the participant, BDR messaging appeals to participants to help keep system costs down and ensure grid reliability.

Since BDR is relatively new, impact evaluation results are limited. A PG&E pilot from the summer 2015 found average peak day impacts of approximately 2%.[21] This places BDR impacts in line with an opt-out TOU rate with a low peak to off-peak ratio. Although modest compared to the other rate strategies considered in this analysis behavioral feedback programs have consistently demonstrated significant cost-effective energy savings so BDR may be a useful strategy to consider in parallel with a broader behavioral conservation initiative.

[21]. Nexant, *Behavioral Demand Response Study – Load Impact Evaluation Report*, January 11, 2016, *available at* http://www.calmac.org/publications/Behavioral_Demand_Response_Study_Final_Report_CALMAC.pdf

5.2 KEY CONSIDERATONS

5.2.1 ECONOMIC EFFICIENCY

While a typical commercial or industrial rate has a fixed cost component, a volumetric component, and a demand component, a typical residential rate mostly consists of volumetric charges, with a small fixed charge and no demand charge. In this typical residential rate, the fixed charge does not fully recover the utility's fixed costs, and so capacity costs are included in the volumetric energy charge. This creates economic inefficiencies, as the hour-to-hour cost charged to consumers does not correspond to the actual cost of supplying electricity, and is likely part of the reason that residential load factors are lower than those for the commercial or industrial sectors.

This economic inefficiency creates a cross subsidization where customers with high load factors subsidize extra costs from customers with low load factors. Further, there is some empirical evidence that low-income customers tend to have flatter load shapes and are thus effectively providing subsidies to non-low-income participants with lower load factors. A 2010 study calculated bills from a large utility using both flat rates and critical peak pricing. As expected, the CPP increased bills for about half of residential customers, and decreased bills for the other half. However, 65% of low-income customers saw immediate bill reductions because of CPP.[22] In addition, reviews of pilot studies have found that low-income customers are as, or almost as, capable of responding to CPP signals as non-low-income customers.[23]

5.2.2 PEAK TO OFF-PEAK RATIO

As more studies emerge looking at the impact of time varying rates, it is becoming clear that the ratio of electric price between peak and off-peak is a key factor in the expected magnitude of peak demand savings. This is intuitive, as the price differential demanded during the peak increases, customers have more incentive to respond to the price signal. Further, it is a very good reason to include critical peak pricing in addition to time of use rates – while there are very few utilities with a TOU peak-to-off-peak ratio higher than four, CPP programs commonly reach a ratio of 10 and higher.[24] In fact, in Michigan, DTE Electric's peak-to-off-peak ratio is almost 24, while Consumer Energy's is about 8.5.[25]

5.2.3 ENABLING TECHNOLOGIES

Studies of TVR to date also show that enabling technologies, especially smart thermostats, provide a significant boost in the demand savings. As mentioned above, the impact evaluation from DTE Electric's TVR pilot showed that smart thermostats caused per-home demand savings during peak events to jump from 12.6% to 44.5%. This result is consistent with other pilot studies performed in other jurisdictions.

5.2.4 OPT-IN VERSUS OPT-OUT

If customers must actively choose to participate in the TVR (opt-in), enrollment rates are significantly lower than if the TVR is the default rate choice (and customers can opt-out). Currently most TVR programs are opt-in, but existing evidence points to an enormous participation gain from creating a default (opt-out) TVR. For example, a Sacramento Utility District (SMUD) pilot program split their customer base into different groups, giving some opt-in TVS, and others opt-out TVRs. It enrolled 18% of customers in the opt-in group of the study, while 96% of customers in the opt-out group were enrolled. In general, based on a survey of existing programs, opt-in programs achieve an average participation rate of 20%, while opt-out programs achieve an average participation rate of 86%.

It is also the case that customers with the highest load and best ability to shift usage to off-peak times are the most likely to opt-in to a TVR rate. It follows that average savings per participant will be lower for an opt-out program

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22. Ahmad Faruqui, Ryan Hledik, and Jennifer Palmer. *Time-Varying and Dynamic Rate Design*, July 2012, *available at* http://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf
23. Ibid.
24. Ahmad Faruqui, A Global Perspective on Time Varying Rates.
25. Michigan Public Service Commission, Overview of Demand Response Programs in Michigan.

compared to an opt-in program. In the SMUD pilot mentioned above, peak reduction during critical peak events dropped from an average of 25% for the opt-in program, to an average of 14% for the opt-out program.

5.2.5 CUSTOMER SATISFACTION

One major concern preventing wide-scale implementation of TVR, especially on an opt-out basis, is fear of customer backlash. However, evidence to date seems to indicate that customers like feeling that they have more control over their electric rates, even if they do not pay close attention to the actual impact, and the few utilities that have implemented opt-out TVRs have not seen widespread backlash or defection. In Michigan, the DTE Electric TVR pilot evaluation performed a survey of participants who had received the time varying rate. Virtually all survey respondents reported a "solid interest in extending their dynamic peak pricing rate structure beyond the formal conclusion of the pilot," and even the customers who did not feel like they were saving money were likely to continue because "they like the greater sense of control and attribution they had under DPP."[26]Analysis

TVR pilots and roll-outs across the United States and rest of the world continue to be evaluated. The most comprehensive meta-analysis of these evaluations is maintained as the Arcturus database by the Brattle Group. The Arcturus database currently contains 210 TVR treatments from across the world.[27] A wide distribution of savings is observed across treatments in the database, based on TVR type with and without enabling technology.[28] (Figure 17) Enabling technology largely refers to wi-fi thermostats in the homes.

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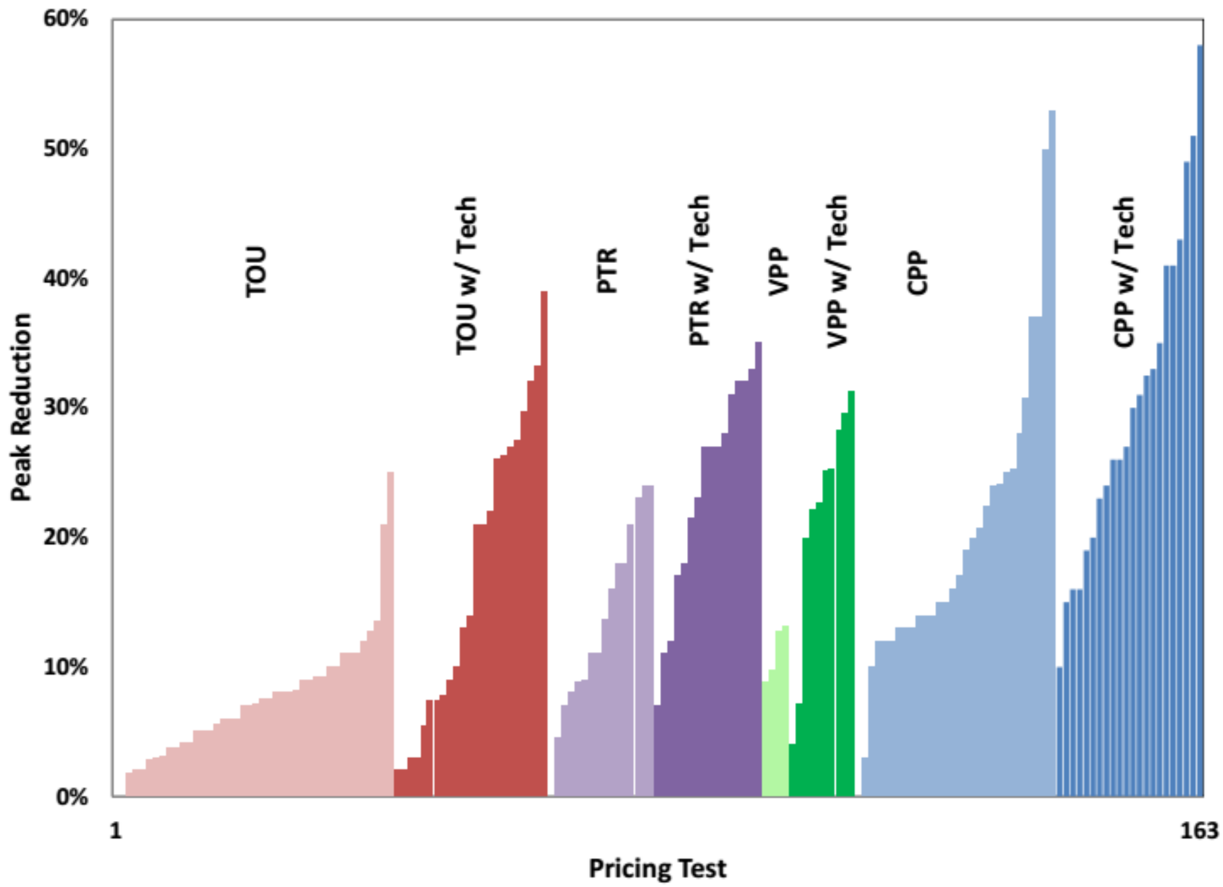
[26]. DTE Energy, *SmartCurrents Dynamic Peak Pricing Pilot Final Evaluation Report,* August 15, 2014, *available at* https://www.smartgrid.gov/files/DTE-SmartCurrents_FINAL_Report_08152014.pdf

[27]. Ahmad Faruqui, A Global Perspective on Time Varying Rates.

[28]. Ahmad Faruqui and Sanem Sergici, *Arcturus: International Evidence on Dynamic Pricing*, The Electricity Journal, July 1, 2013, *available at* https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2288116

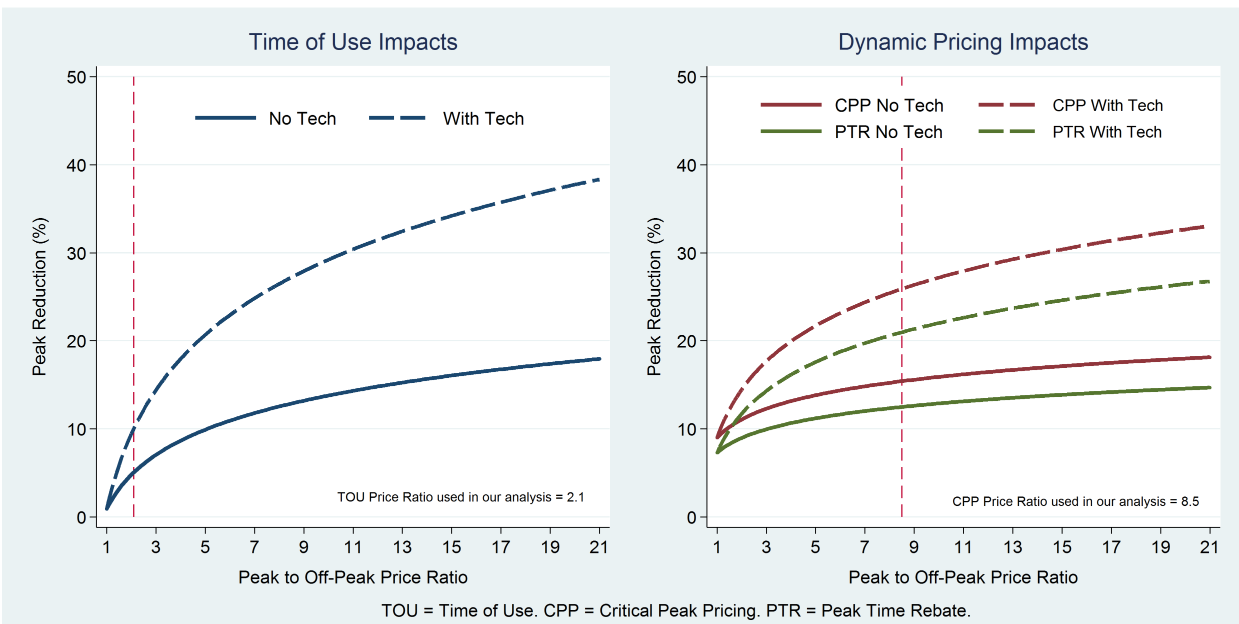
Figure 17: Predicted Demand Reductions by Strategy and Peak to Off-Peak Ratio



While there is considerable variability both within and across rate strategies, more than 60% of tests produced average peak savings of 10% or greater. Only 18% produced savings of lower than 5%, and these studies were primarily TOU-only groups, with lower peak to off peak price ratios.

To facilitate predictions of expected savings, the Brattle Group grouped each trial result by TOU rate vs. other TVR types, and developed regression equations. The research team plotted the fitted equations, with and without enabling technology, for the pricing strategies considered. (Figure 17) The vertical lines represent the peak to off-peak price ratios used to estimate peak demand reduction potential for various TVR strategies. (Table 16)

Figure 18: Predicted Demand Reductions by Strategy and Peak to Off-Peak Ratio



For the analysis of residential TVR potential in the Lower Peninsula, we rely largely on the existing impact evaluations, as compiled in the Arcturus database. As a check, the regression equation for DPP impacts from the Arcturus database would predict that DTE Electric's DPP rate, with a peak to off-peak pricing ration of 23.8, would produce an average peak reduction of 18.5% without enabling tech, and 34% with enabling tech. This compares with actual evaluation findings of 12.6% without enabling tech and 44.5% with enabling tech. While somewhat different than the results predicted by the Arcturus regression, they are within the range of expected variation. Thus, we used the regression equations for this analysis, as they are based on a larger number of pricing experiments, and because they allow us to predict the change in impact as we vary certain parameters. We supplement the regression equations with data showing general average reduction by type of TVR, as well as data from the SMUD pilot showing the expected difference in average savings between opt-in and opt-out programs. We use an on-peak to off-peak pricing ratio of 2.1 for TOU rates, and 8.5 for CPP and PTR rates. These ratios are conservative, as they represent the ratios for Consumer Energy's proposed rates. The peak to off-peak ratios for DTEs current time varying rate are much higher, at 3.0 for the TOU component and 23.8 for the CPP.

5.2.6 RESULTS

The research team estimated expected 2026 demand savings under time-of-use rates, critical peak pricing, and peak time rebates, under opt-in and opt-out scenarios, and with and without enabling technology (connected thermostats). (Table 16) We have assumed that full deployment of AMI by 2026, enabling all residential customers to participate. Increased saturation of connected thermostats will occur with or without dynamic rate design so the "no thermostats" option is presented primarily to illustrate the increased opportunity presented by enabling technology. For the scenarios with enabling technology, it is assumed that the connected thermostat penetration will grow as defined in Section 4.2.

Table 16: TVR Potential Estimates by Enrollment Strategy and Rate Type

TVR Scenario	Average % Reduction per Participant			Total 2026 MW Reduction			2026 Reduction as % of Residential Peak Forecast		
	TOU	CPP	PTR	TOU	CPP	PTR	TOU	CPP	PTR
Opt-in, no thermostats	5.0%	15.4%	12.4%	94	289	233	1.0%	3.1%	2.5%
Opt-in thermostats	10.0%	25.9%	20.9%	138	382	308	1.5%	4.1%	3.3%
Opt-out, no thermostats	2.8%	8.6%	7.0%	221	679	548	2.4%	7.2%	5.9%
Opt-out, thermostats	5.6%	14.5%	11.7%	243	723	584	2.6%	7.7%	6.2%

TOU = Time of Use. CPP = Critical Peak Pricing. PTR = Peak Time Rebate.

These results illustrate that TVRs have the potential to significantly impact peak demand and raise the residential load factor. As discussed, Michigan utilities are currently implementing opt-in Dynamic Peak Pricing plans that combine TOU rates with CPP on specific peak days. As Michigan makes this pricing available to all customers, savings could reach 4% of the residential sector summer peak demand forecast. This number could almost double if utilities decide to make TVRs the default residential rate, and could otherwise grow from more aggressive marketing campaigns or from a faster than projected increase in the adoption of connected thermostats. Regardless of the specifics, TVRs have the potential to become a highly cost-effective method for reducing the peak demand and increasing the economic efficiency of electric power system in Michigan.

Specific costs for TVRs are hard to estimate, and vary significantly depending on the utility's existing AMI and data management systems. However, once AMI is in place (which is already happening aggressively in Michigan) costs are not hugely significant. Additional costs may include:

- Upgrades to the billing system and meter data management to handle significantly more data
- Operational support including project management, call center operations, and other ongoing administrative costs
- Technology and staff to provide customers with reliable advance notifications
- Education and outreach
- Incentives for thermostat if offered in conjunction with the TVRs

Although these costs are real, they are largely frontloaded and typically much smaller than the benefits. Since the costs are so variable, we do not attempt an estimate. Instead, we assume that the UCT ratio for time varying rates at least 2.0 for the Low avoided cost scenario, 4.0 for the Medium case, and 6.0 for the High case.

With PTRs, the customer incentive would be sized based on the value of the peak demand reduction so a program administrator would set the incentive level based on the avoided costs, and desired magnitude of impact and cost-effectiveness level. While the peak demand reduction potential for an opt-out design is far higher than an opt-in design in aggregate, opt-out savings may be slightly more expensive on a per-kW basis because average reduction per participant is lower and this could lead to a lower ratio between benefits and volumetric administrative costs.

SECTION 6 POLICY CONSIDERATIONS

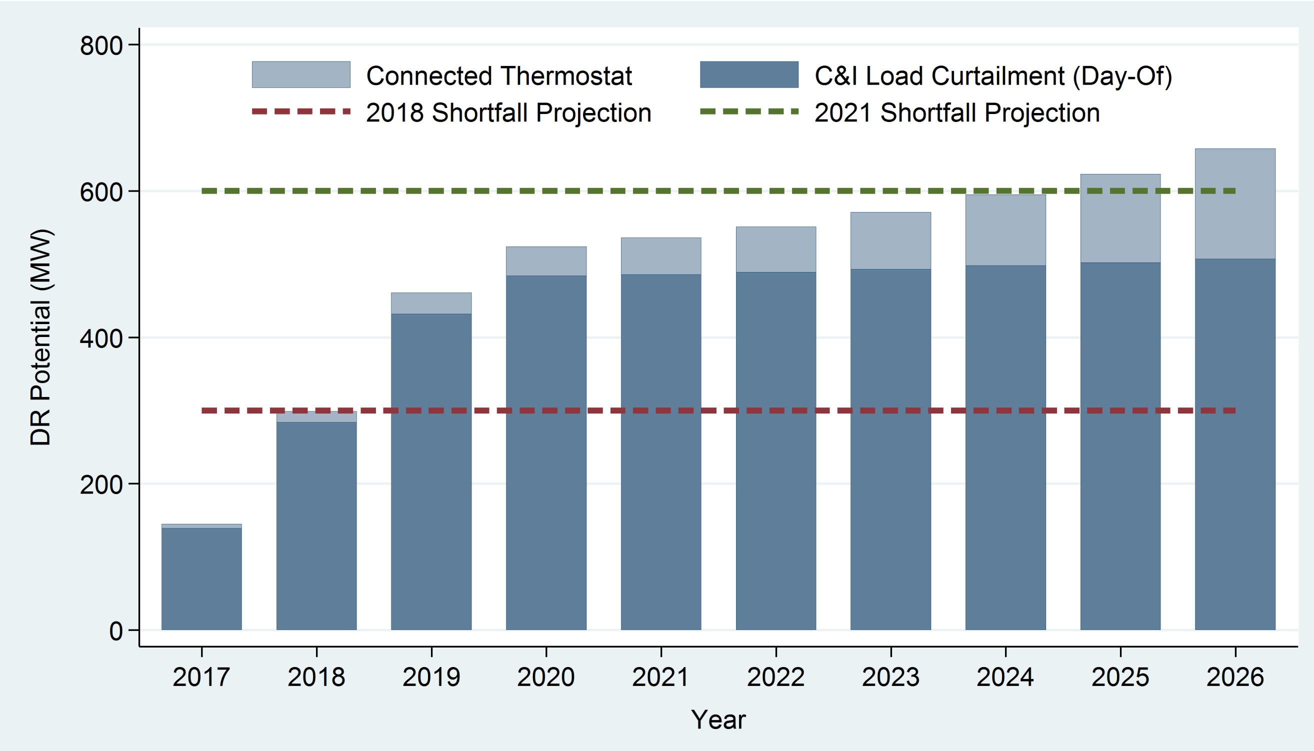
Michigan faces many important decisions over the next decade as the electric grid modernizes. Currently, approximately 10% of electric system capacity is built to meet demand in just 1% of the hours of the year. These costs are ultimately borne by Michigan homes and businesses so it is important that policies in the state recognize and enable opportunities to secure strategic demand reductions to ensure capacity requirements are met in the most cost-effective way possible. This paper has examined the opportunities for peak demand reductions in the residential sector from time varying rates and connected thermostats, and in the commercial and industrial sectors from an incentive-based dispatchable DR strategy. Recently passed legislation established a solid foundation and provides IOUs a financial incentive to pursue demand reductions in resource planning. Significant peak demand reduction potential exists in each area, with the magnitude of the opportunity ultimately determined by the value of the generation capacity the strategy is intended to offset or defer.

If Michigan IOUs and policy makers are faced with a decision to construct a new combined cycle natural gas power plant or implement strategic demand reductions, each of the DR strategies analyzed here is a far more cost-effective solution. In the 'High' avoided cost scenario, we estimate almost 1,600 MW of C&I DR potential from a day-ahead notification and 200 MW of residential DR potential from connected thermostats. If time-varying rates are deployed in the residential sector, the residential potential increases significantly. In combination, these strategies could more than offset MISO's projection of 1,970 MW of summer peak demand load growth from 2017 to 2026.

We also considered a scenario where historic capacity surpluses in the Midwest remain and the lower capacity prices of recent years persist. Both TVR and C&I DR still present hundreds of MW of cost-effective opportunities, but the economics of a connected thermostat offering appear marginal. Between the Low and High scenarios lies the most likely market equilibrium. In the Medium avoided cost scenario explored in this report, we identified almost 1,400 MW of peak demand reduction potential that would deliver $900 million in benefits compared to $400 million in costs – for net benefit to the state of $500 million dollars. [29] The combination of a connected thermostat offering and a C&I DR design with day-of notification could virtually erase the often-cited Michigan generation shortfall projections of 300 MW by 2018 and 600 MW by 2021. (Figure 19) With a day-ahead C&I design, or a broad rollout of TVR in the residential sector, potential from the combined strategies exceeds MISO's shortfall projections.

[29]. Costs, benefits, and savings are calculated in the year they are expected to occur (e.g. not discounted to reflect the net present value in the first year of the study horizon)

Figure 19: Demand Reduction Potential by Year vs. Capacity Shortfall Projections



The peak demand reduction potential estimates from time-varying rates are increased significantly when coupled with smart devices like connected thermostats and when the TRV is the default rate design (opt-out) as opposed to an opt-in offering. Opt-out TVR strategies are more aggressive and likely aligned with a high avoided cost scenario where reductions are needed to defer large capital investments. Opt-in TVR designs have been tested more broadly in the United States and are more aligned with a Low or Medium avoided cost scenario where the alternative supply side options are more economical. The market share of connected thermostats and other home automation devices in Michigan will expand significantly over the next decade. There is a clear opportunity at the intersection of smart devices and smart rate design to manage peak demand growth in a way that is greater than either strategy is capable of in isolation.

As decision makers consider meeting potential additional capacity requirements in the Lower Peninsula, demand response is a more cost-effective resource than building new generation supply. We hope that system planners and policy makers will consider the significant cost savings associated with the demand reduction strategies examined in this paper.

SECTION 7 APPENDIX

7.1 ELASTICITY OF DEMAND

The analytical approach used for C&I demand response is a 'top-down' method that uses price elasticity of demand coefficients to model DR potential under various conditions. Price elasticity of demand is the percentage change in the *quantity* of electricity demanded divided by the percentage change in the *price* (e.g., including an incentive) of DR. Elasticity of demand coefficients will be negative as the quantity demanded goes down when the price goes up.

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price} \tag{1}$$

Where:

$$\%\ change\ in\ Quantity = \frac{(New\ Quantity - Original\ Quantity)}{Original\ Quantity} * 100\% \tag{2}$$

And:

$$\%\ change\ in\ Price = \frac{(New\ Price - Original\ Price)}{Original\ Price} * 100\% \tag{3}$$

For a fixed elasticity and a fixed percentage change in price, it is possible to calculate the percentage change in the quantity of DR supplied by rearranging the terms in Equation (1):

$$\%\ change\ in\ Quantity = (Elasticity) * (\%\ change\ in\ Price) \tag{4}$$

Coupling Equation (4) with the disaggregated peak demand forecast discussed in Section 2.2 and retail electric rates from EIA[30], it is possible to estimate how much DR potential exists in each market segment by solving Equation (5) for "DR potential":

[30]. A 2017 retail electric rate of \$0.075 per kWh was assumed for industrial customers and \$0.107 per kWh was used for commercial segments. Retail rates were escalated 2% annually each year of the study horizon.

$$\% \ change\ in\ Quantity = \frac{(Summer\ peak - \ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\% \qquad (5)$$

Note that Equation (2) and Equation (5) are the same: the original quantity is the summer peak and the new quantity is the summer peak minus DR potential. Also, note that the percentage change in the quantity of electricity demanded will be negative. This makes sense, as demand response entails a decrease in electric consumption during peak hours.

To implement Equations (4) and (5), estimates of elasticity are needed. To that end, the elasticity estimates used in our analysis are drawn from the Demand Response Potential Study Report for Pennsylvania[31] (Table 17) The elasticity estimates for that report were calculated by Nexant based on data from non-residential DR programs in California. The variables included in the California analysis were (1) the level of load reduction, (2) the incentive level, and (3) the DR dispatch type – a measure of the time between the DR event and when participants were notified of the event. One useful feature of elasticity coefficients is they are unit-less (percent changes in load and price), so the differences in retail electric costs between California and Michigan do not create an issue.

[31]. GDS Associates and Nexant, Inc, *DR Potential Study Report for Pennsylvania*, Table 6-2, February 15, 2015, *available at* http://www.puc.pa.gov/pcdocs/1345077.docx; Note that the Pennsylvania report expressed the coefficients as positive (elasticity of DR supply).

Table 17: Elasticity Estimates by DR Dispatch Type

Segment	Day-Ahead	Day-Of
Education	-0.009	-0.003
Grocery	-0.010	-0.009
Health	-0.021	-0.007
Industrial	-0.013	-0.007
Lodging	-0.010	-0.005
Office	-0.010	-0.005
Other	-0.011	-0.006
Restaurant	-0.010	-0.005
Retail	-0.010	-0.009
Warehouse	-0.036	-0.045

Using the elasticity estimates, fixed incentive levels, and Equations (3) through (5), DR potential can be estimated. Consider this example:

The estimated summer peak demand forecast for LRZ7 in 2017 is 21,457 MW. As noted in Section 2.2, 42.4% of this peak (9,098 MW) is assumed to be attributable to the commercial sector. (Table 5) Approximately 9% of the commercial peak (819 MW) is assumed to be attributable to restaurants. (Figure 6) What DR potential exists in this customer segment? Suppose all restaurants are offered to participate in a day-ahead notification DR program and the retail electric rate is $0.107 per kWh. Further, let us assume a total of 24 DR program hours will be called and the DR incentive amount is $30 per kW-year. This incentive amount can be converted to a $/kWh basis (to line up with the retail electric rate) by dividing by the number of program hours:

$$\frac{\$30\ incentive\ per\ kW}{24\ hours} = \$1.25\ incentive\ per\ kWh$$

Thus, on a $/kWh basis, the incentive payment is $1.25. Note that without DR, the "incentive" payment is the same as the retail rate. That is, for each kWh the customer does not use, the customer saves $0.107. Using $1.357 as the new price (because using a kWh will cost both the retail rate and the missed opportunity for an incentive), the percentage change in the price of DR can be estimated:

$$\%\ change\ in\ Price = \left(\frac{\$1.357 - \$0.107}{\$0.107}\right) * 100 = 1168\% \qquad (3)$$

Next, multiply the percentage change in price by the appropriate elasticity estimate to get the percentage change in the quantity of demanded (or DR supplied):

$$\%\ change\ in\ Quantity = (-0.01) * (1168\%) = -11.68\% \tag{4}$$

This percentage can then be plugged into Equation (5), leaving DR Potential as the lone unknown variable:

$$-11.68\% = \frac{(819\ MW - \ DR\ potential) - 819\ MW}{819\ MW} * 100\% \tag{5}$$

Finally, solve Equation (5) for DR potential:

$$DR\ Potential = 95.7\ MW$$

Thus, in this example with the assumed conditions, there is an estimated 95.7 MW of DR potential in the restaurant sector. Note that this estimate will change as the incentive payment (assumed to be $30 per kW in this example) and the total number of DR program hours (assumed to be 24 hours in this example) change. This example also assumes that the program is offered/marketed to all accounts in the customer segment. For the commercial segments of the forecasts our model assumes that only half of the load is attributable to accounts to are large enough or capable of reducing sufficient load to qualify for this type of program offering. For the industrial sector, all load was considered eligible.