Michigan Demand Response Statewide Potential Study (2021-2040)

DRAFT

Prepared for:

LARA MPSC

State of Michigan

Department of Licensing and Regulatory Affairs

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Common Acronyms

AC	Air Conditioning
ACEEE	American Council for an Energy Efficient Economy
BEV	Battery Electric Vehicle
BTM	Behind-the-Meter
BYOD	Bring Your Own Device
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
Consumers	Consumers Energy
COVID-19	Coronavirus 2019
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
DERMS	Distributed Energy Resource Management System
DI	Direct Install
DLC	Direct Load Control
DOE	United States Department of Energy
DR	Demand Response
DRSim™	Guidehouse's Proprietary Demand Response Simulator
DSM	Demand-Side Management
DSMore	Demand Side Management Option Risk Evaluator
DTE	DTE Energy
EE	Energy Efficiency
EIA	US Energy Information Administration
EMCS	Energy Management and Control System
EMS	Energy Management System
ES	Energy Storage
EV	Electric Vehicle
EWR	Energy Waste Reduction
FERC	Federal Energy Regulatory Commission

FTE	Full-Time Equivalent
HVAC	Heating, Ventilation, and Air Conditioning
I&M	Indiana Michigan Power
IDSM	Integrated Demand-Side Management
IT	Information Technology
kW	Kilowatt
kWh	Kilowatt-Hour
LED	Light-Emitting Diode
LF	Load Factor
MGU	Michigan Gas Utilities
MISO	Midcontinent Independent System Operator
MPSC	Michigan Public Service Commission
MW	Megawatt
N/A	Not Applicable
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NSP	Northern States Power
NTG	Net-to-Gross
O&M	Operation and Maintenance
PHEV	Plug-in Hybrid Electric Vehicle
PJM	PJM Interconnection
PTR	Peak Time Rebate
PV	Present Value
RTP	Real-Time Pricing
SEER	Seasonal Energy Efficiency Ratio
SEMCO	SEMCO Energy Gas Company
TES	Thermal Energy Storage
TOU	Time-of-Use
UCT	Utility Cost Test

UMERC	Upper Michigan Energy Resources Corporation
UPPCO	Upper Peninsula Power Company
US	United States
VO	Voltage Optimization
YR	Year

Executive Summary

The Michigan Public Service Commission (MPSC) engaged Guidehouse Inc. (Guidehouse) to prepare a demand response (DR) potential assessment across the State of Michigan from 2021 to 2040. The objective of this assessment was to estimate the potential for cost-effective DR, also known as active demand reduction or active demand management, as a capacity resource to reduce customer loads during peak summer periods. The study was conducted simultaneously with a study (reported separately) of energy waste reduction (EWR) potential for the same time period.

Guidehouse worked with utilities from the State of Michigan to identify relevant DR program types in Michigan and the applicability of these program types by customer segments and end uses to realize summer peak load reductions. Guidehouse developed achievable potential estimates for the different DR program and measure types at various levels of disaggregation, and the associated costs for implementation of a DR program portfolio. The assessment covered different types of controls for curtailing load at customer premises, which include conventional and advanced control methods. Guidehouse also conducted cost-effectiveness assessment of the DR program and measure types included in the assessment and represented the potential for the cost-effective options.

Summary of Analysis Approach

Guidehouse developed the State of Michigan's DR potential and cost estimates using a bottom-up analysis. The analysis used customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR program information from Michigan utilities, and well-established and latest available information from the industry on DR resource performance and costs. These sources provided input data to Guidehouse's Demand-Response Simulator (DRSim™) model, which calculates total DR potential across Michigan. Figure ES-1 summarizes the DR potential estimation approach.

Figure ES-1. DR Potential Assessment Steps

Step 1: Market Characterization	Characterize market for DR potential estimation: Segment market for DR potential assessment and develop number of customers and coincident peak load estimates by segment for base year.
Step 2: Develop Baseline Projections	Define peak and develop baseline peak demand projections over the study period (2021-2040).
Step 3: Define DR Options	Define and characterize DR options and associated enabling technologies, and map applicable options to relevant customer classes.
Step 4: Define Key Assumptions for Potential and Costs	Develop assumptions for participation, unit load reduction, and itemized costs for each DR option.
Step 5: Estimate Potential, Costs, and Cost-effectiveness	Develop assumptions for participation, unit load reduction, and itemized costs for each DR option.
Step 6: Undertake Scenario Analysis	Present potential results by scenario, which consider baseline adjustments, and participation scenarios with varying incentives.

The segmentation of residential customers is based on the approach followed in the EWR potential study conducted by Guidehouse in conjunction with the DR potential study. The segmentation of C&I customers is based on maximum demand values, which were developed using the participating Michigan utilities' rate schedules, retail sales, and demand data. Table ES-1 describes the different levels at which Guidehouse segmented the market for this DR assessment.

Table ES-1. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: By Sector	• Residential • Commercial and Industrial (C&I)
Level 2: By Customer Segment	• Residential – Single-Family – Multifamily – Single-Family Low Income – Multifamily Low Income • Electric C&I customers by size, based on maximum demand values:[1] – Small C&I (< 30 kW) – Medium C&I (30-200 kW) – Large C&I (201-1,000 kW) – Extra-Large C&I (>1,000 kW) • Natural gas C&I customers by annual consumption – Small C&I (<14,000 therms) – Large C&I (≥14,000 therms)
Level 3: By Region	• Lower Peninsula Electric • Upper Peninsula Electric • Lower Peninsula Natural Gas • Upper Peninsula Natural Gas

Source: Guidehouse analysis

Characterization of DR Options

The potential assessment considered a broad spectrum of DR options. These DR options represent the DR programs and rates that Michigan utilities currently offer and could potentially offer based on existing and emerging DR programs and enabling technology offers in the industry. Table ES-2 describes the DR options included in the study.

Table ES-2. Descriptions of DR Options

DR Options	Brief Description	Eligible Customers
Electric DR Options		
Direct Load Control (DLC) Switch for Space Cooling and Heating, Water Heating	Control of space cooling and heating equipment (central air conditioning, heat pumps, electric furnaces), and electric water heating using load control switches	All residential, small C&I, and medium C&I customers with eligible end uses.
DLC-Smart Thermostat BYOT	Bring your own thermostat (BYOT) program with space cooling and heating control using smart thermostats.	All residential, small, and medium C&I customers with smart thermostats

[1] The segmentation by size for DR and energy efficiency is different. The size segmentation for DR is based on the type of end-use control technology and the type of DR program offer. The demand thresholds presented here for segmentation by size is typically what is considered for DR potential studies.

DR Options	Brief Description	Eligible Customers
Smart Appliances Control (including Room Air Conditioning)	Remote control of Wi-Fi-enabled smart appliances; appliances may also be controlled using a smart plug	Residential customers with smart appliances
Behavioral DR	Modifications in demand during peak demand period due to behavioral changes, induced by social comparisons.	All residential
Capacity Reduction	Firm capacity commitment for load reduction during DR events; customers receive both a fixed capacity payment ($/kW) based on committed load reduction, plus an energy payment ($/kWh). Curtailment can be either manual or automated.	Large C&I, extra-large C&I
Demand Bidding	Voluntary load reduction when DR events are called. There is no capacity commitment. Customers voluntary reduce load and receive energy payment ($/kWh) only based on. Curtailment can be either manual or automated.	Large C&I, extra-large C&I
Time-Of-Use (TOU) Rates	Rates that vary by block of hours during the day and by season	Residential, all C&I
Critical Peak Pricing (CPP)	Significantly higher price during certain critical hours of the year (high demand), superimposed on a TOU rate; off-peak rate is lower than an otherwise applicable tariff.	Residential, all C&I
Peak Time Rebate (PTR)	Discounted rate for reducing electricity use over baseline during DR events.	Residential, small C&I
Real Time Pricing (RTP)	Dynamic rate with hourly variation in price.	Large C&I, extra-large C&I
Electric Vehicle (EV) Load Control	Managed Charging of plug-in hybrid electric vehicles (PHEVs) and EVs.	Customers with PHEVs and EVs
Behind-the-Meter (BTM) Battery	Dispatch of BTM batteries during DR events.	Customers with BTM batteries
Thermal Energy Storage (TES)	Load shifting to TES systems (either ice storage or phase change materials) during DR events	All C&I customers with TES system
Voltage Optimization (VO)	Energy and demand reduction using front-of-the-meter VO technologies.	All
Natural Gas DR Options		
DLC-Smart Thermostat BYOT	Bring your own thermostat (BYOT) program with space cooling and heating control using smart thermostats.	All residential and small C&I customers with smart thermostats for gas space heating control

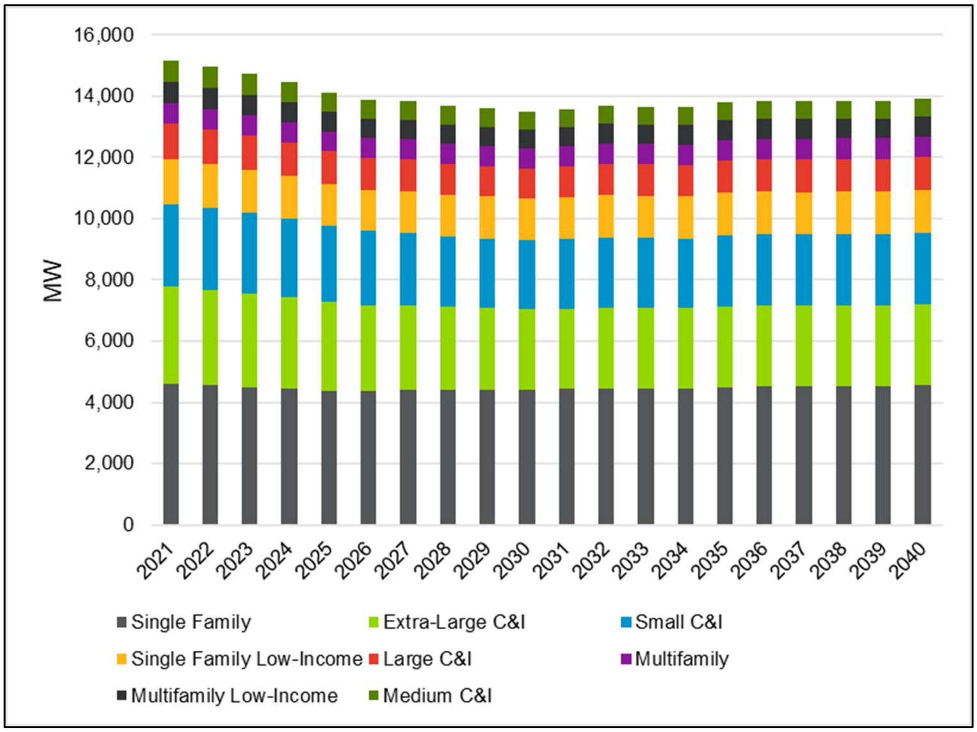
DR Options	Brief Description	Eligible Customers
DLC-switch for Water Heating	Control of gas water heating using load control switches	All residential and small C&I, customers with gas water heating
Behavioral DR	Modifications in demand during peak demand period due to behavioral changes, induced by social comparisons.	All residential
Capacity Reduction	Firm capacity commitment for load reduction during DR events; customers nominate a certain reduction amount, similar to electric and get paid based on their nomination and actual energy reduced during DR events.	Large C&I

Source: Guidehouse

Baseline Peak Demand Projections

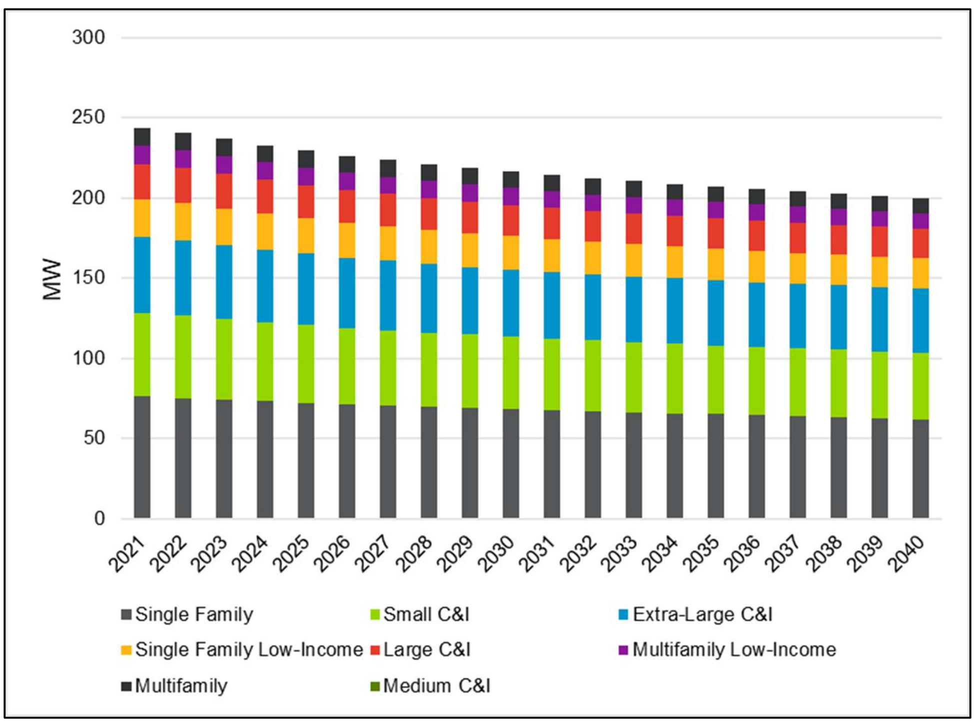
The baseline peak demand projections serve as a foundation for the DR potential assessment. Guidehouse developed disaggregated peak demand projections by region, peak period, customer segment, and end-use based system peak demand forecast provided by individual utilities; Reference Scenario sales forecast developed as part of the energy efficiency potential assessment; and end-use load profiles provided in a historical Demand Side Management Option Risk Evaluator (DSMore) study. The baseline demand projections for DR potential assessment are net of demand reductions from EWR measures. Figure ES-3 and Figure ES-3 show the electric summer baseline peak demand projections by customer segment for the Lower Peninsula and the Upper Peninsula. The downward trend is due to EWR savings over time which leads to a lowering and near flattening of the baseline peak demand for DR.

Figure ES-2. Lower Peninsula Reference Scenario Summer Baseline Electric Peak Demand Projection by Customer Class (Net of EWR, MW at Meter)



Source: Guidehouse analysis

Figure ES-3. Upper Peninsula Reference Scenario Summer Baseline Electric Peak Demand Projection by Customer Class (Net of EWR, MW at Meter)



Source: Guidehouse analysis

Summary of Potential and Cost Results

Guidehouse first assessed the cost-effectiveness of DR options for each region and peak period for the Reference Scenario using the Utility Cost Test (UCT) test, and using weighted avoided costs provided by utilities. In coordination with the MPSC, it was determined that any electric DR option with a UCT test benefit-cost ratio greater than 0.8 would be included in the estimate of potential, to consider a broader portfolio of technology and program types for future program planning purposes. Guidehouse then assessed cost-effectiveness under the Carbon Price Scenario and Aggressive Scenario (which represent higher incentive costs, participation, and DER adoption than the Reference Scenario). The study assessed cost-the effectiveness of the DR options over the study timeframe, 2021-2040. Only DR options that were cost-effective over the study timeframe, using a UCT 0.8 benefit-cost ratio threshold, were included in the potential estimates. As discussed in Section 2.5.4, cost-effectiveness screening was not conducted for natural gas measures.

Cost-Effectiveness, Potential, and Cost Results

Table ES-3 shows the long-term cost-effectiveness results of summer electric DR options under the Reference Scenario for the Lower Peninsula and the Upper Peninsula. In the Lower Peninsula, all but two DR options were cost-effective—Bring Your Own Device (BYOD) smart appliances control, and TES. Four DR options—Electric vehicle (EV) managed charging, DLC switch, BYOD smart appliances control, and TES options—were not cost-effective in the Upper Peninsula. This result was based on a UCT cost-effectiveness cut-off of a 0.8 benefit-cost ratio.

Table ES-3. Reference Scenario Benefit-Cost Ratios by DR Options

DR Options	Lower Peninsula	Upper Peninsula
	UCT Benefit-Cost Ratio (2021-2040)	
Real Time Pricing (RTP)	12.3	17.0
Time-of-Use (TOU)	11.4	11.8
C&I Demand Bidding	5.0	3.9
C&I Capacity Reduction	3.7	3.0
Critical Peak Pricing (CPP)	3.4	2.7
Voltage Optimization (VO)	2.0	1.4
Bring Your Own Thermostat (BYOT)	1.8	1.3
Behind-the-Meter (BTM) Battery Dispatch	1.6	1.2
Behavioral DR	1.5	1.1
Peak Time Rebate (PTR)	1.1	1.0
Electric Vehicle (EV) Managed Charging	0.9	0.5
Direct Load Control (DLC)-Switch	0.8	0.5
Smart Appliances Control (Bring Your Own Device)	0.2	0.2
Thermal Energy Storage (TES)	0.1	0.1

Source: Guidehouse analysis

Table ES-4 and

Table ES-5 show the cost-effectiveness results across the three scenarios for all DR options for the Lower Peninsula and the Upper Peninsula.

The cost-effectiveness results do not change between the Reference Scenario and the Carbon Price Scenario. The avoided capacity costs are the same between the Reference Scenario and Carbon Price Scenario, which is the primary driver of DR benefits.[2] The Carbon Price Scenario modeled higher adoption of EVs and BTM batteries, but other than that, costs and impact assumptions remained unchanged between the Reference Scenario and the Carbon Price Scenario. Therefore, the benefit-cost ratios are the same between the two scenarios, except for very slight changes to the benefit-cost ratios for the EV and BTM Battery options.

The Aggressive Scenario assumed higher participation levels in DR options under higher incentive levels, which leads to lower benefit-cost ratios. For the Aggressive Scenario, the two DR options that are not cost-effective for the Lower Peninsula are DLC-switch and EV Managed Charging, in addition to the two DR options (Smart Appliances Control and TES) that were not cost-effective under the Reference Scenario. For the Upper Peninsula, cost effectiveness screening remains unchanged between the Aggressive Scenario and Reference Scenario.

Table ES-4. Benefit-Cost Ratio Comparisons by Scenarios of DR Options (Electric) for Lower Peninsula (Summer)

DR Option	Reference	Aggressive	Carbon Price
	UCT Benefit-Cost Ratio (2021-2040)		
Real Time Pricing (RTP)	12.3	7.2	12.3
Time-of-Use (TOU)	11.4	11.3	11.4
C&I Demand Bidding	5.0	3.8	5.0
C&I Capacity Reduction	3.7	3.2	3.7
Critical Peak Pricing (CPP)	3.4	3.2	3.4
Voltage Optimization (VO)	2.0	2.4	2.0
Bring Your Own Thermostat (BYOT)	1.8	1.5	1.8
Behind-the-Meter (BTM) Battery Dispatch	1.6	1.2	1.7
Behavioral DR	1.5	1.5	1.5
Peak Time Rebate (PTR)	1.1	0.9	1.1
Electric Vehicle (EV) Managed Charging	0.9	0.7	0.8
Direct Load Control (DLC)-Switch	0.8	0.7	0.8
Smart Appliances Control (Bring Your Own Device)	0.2	0.2	0.2
Thermal Energy Storage (TES)	0.1	0.1	0.1

Source: Guidehouse analysis

[2] Even though the avoided energy costs are higher in the Carbon Price Scenario than the Reference Scenario, the avoided energy costs have relatively much smaller contribution to DR benefits than avoided capacity costs.

Table ES-5. Benefit-Cost Ratio Comparisons by Scenarios of DR Options (Electric) for Upper Peninsula (Summer)

DR Option	Reference	Aggressive	Carbon Price
	UCT Benefit-Cost Ratio (2021-2040)		
Real Time Pricing	17.0	11.3	17.0
Time-Of-Use	11.8	11.4	11.6
C&I Demand Bidding	3.9	3.1	3.9
C&I Capacity Reduction	3.0	2.4	2.7
Critical Peak Pricing	2.7	2.9	3.0
Voltage Optimization	1.4	1.4	1.4
Bring Your Own Thermostat	1.3	1.2	1.3
Behind-the-Meter (BTM) Battery Dispatch	1.2	0.9	1.2
Behavioral DR	1.1	1.1	1.1
Peak Time Rebate	1.0	0.8	1.0
Electric Vehicle Managed Charging	0.5	0.4	0.6
Direct Load Control-Switch	0.5	0.4	0.5
Smart Appliances Control (Bring Your Own device)	0.2	0.2	0.2
Thermal Energy Storage (TES)	0.1	0.1	0.1

Source: Guidehouse analysis

Achievable Potential Results by DR Option

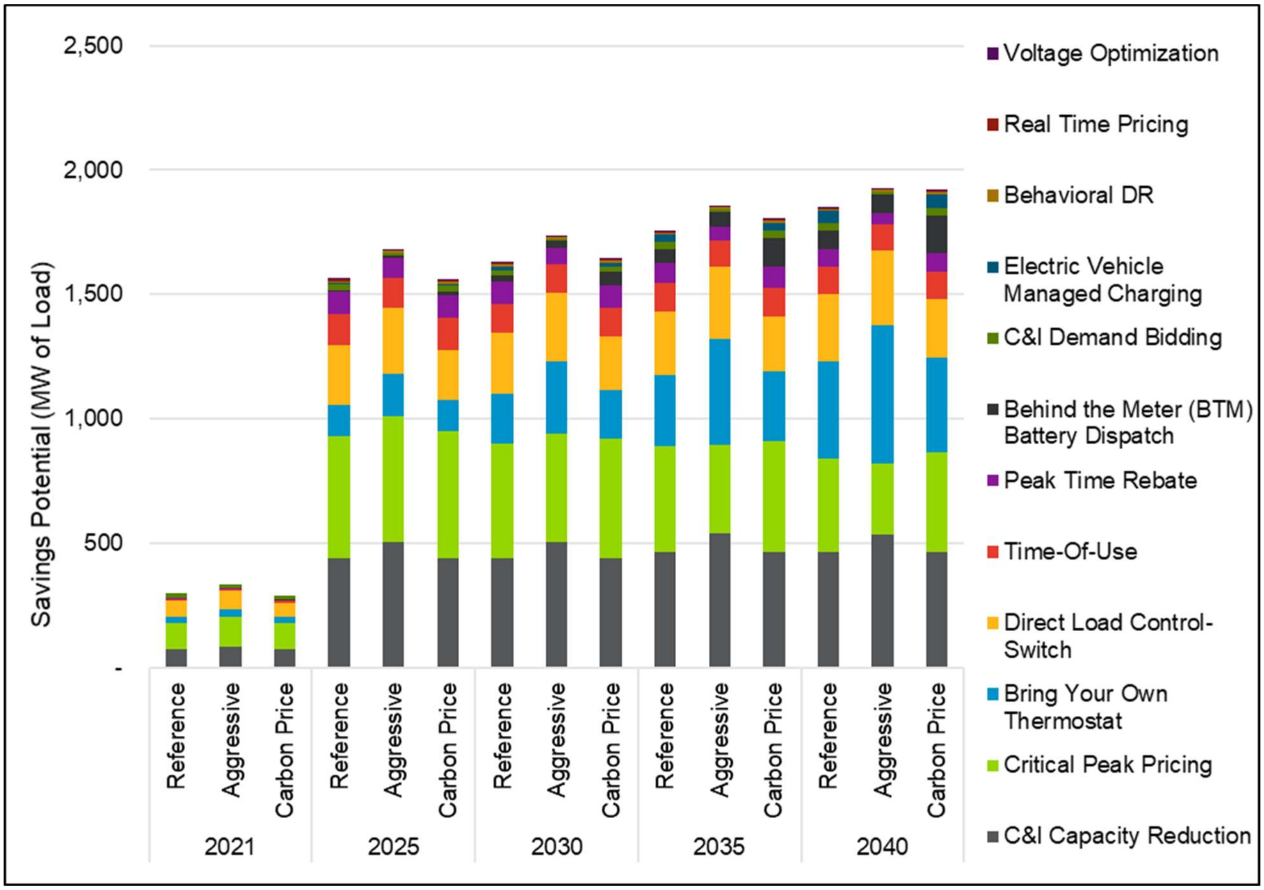
Figure ES-4 shows the MW breakdown of the Lower Peninsula achievable potential by DR option for selected years, and Figure ES-5 shows the achievable potential as a percentage of the participating utilities' peak demand.[3] The Reference Scenario achievable potential increases steadily from around 300 MW of summer peak reduction potential in 2021 (translates to around 2% reduction in summer peak demand forecast in 2021 for the Lower Peninsula) to around 1,850 MW of peak demand in 2040 (translates to around 10% reduction in summer peak demand forecast in 2040 for the Lower Peninsula). The top four DR options that constitute over 80% of the total cost-effective potential are – C&I Capacity Reduction, BYOT, CPP, and DLC-switch.

The Aggressive Scenario consistently has the highest potential due to the increased participation assumed in this scenario, despite the removal of the non-cost-effective measures. In the long-term, it has an average 5% higher potential than the Reference Case.

Potential in the Carbon Price Scenario grows to exceed the Reference Scenario in the later years due to the increased adoption of enabling technologies, namely smart thermostats, EVs, and batteries.

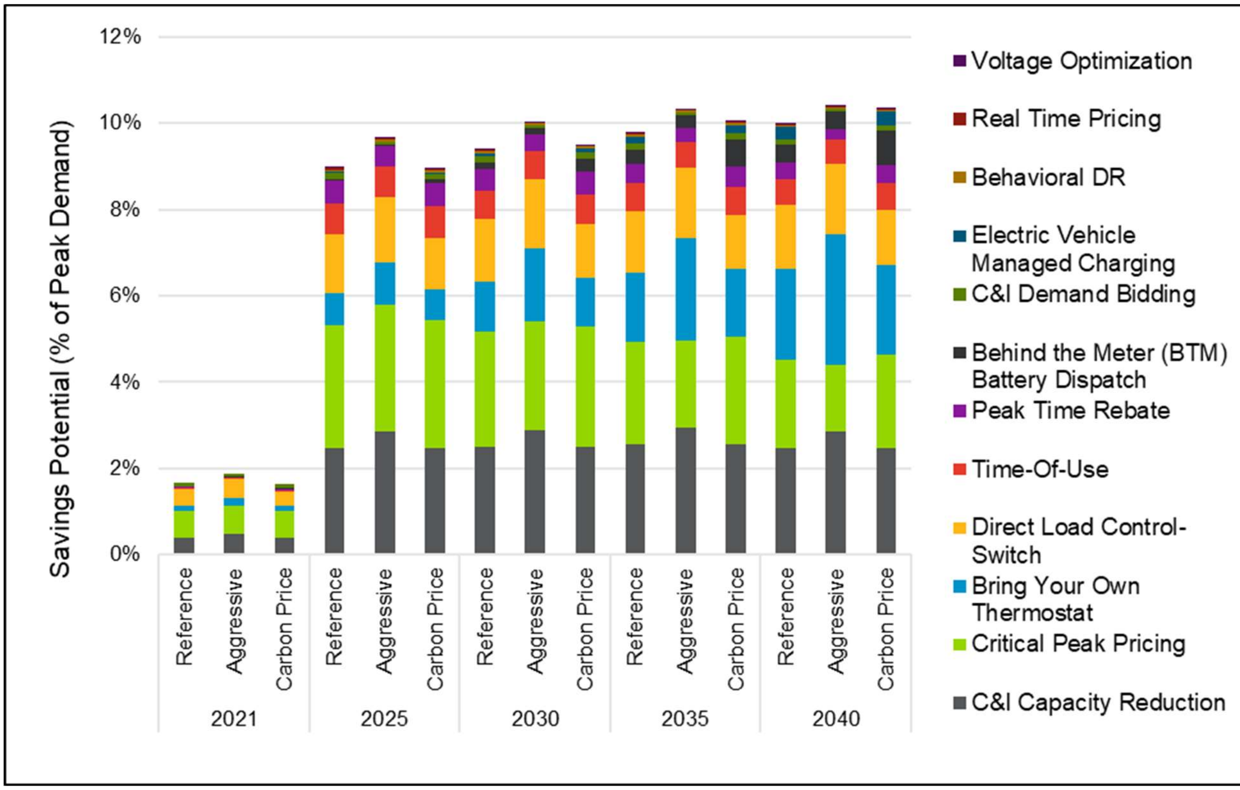
[3] The peak demand used for the percentage calculation is the system peak demand value based on Energy Information Administration (EIA) data to that includes loads from municipal utilities and cooperatives.

Figure ES-4. Lower Peninsula Electric Summer Achievable Potential by DR Option and Scenario (MW at Meter)



Source: Guidehouse analysis

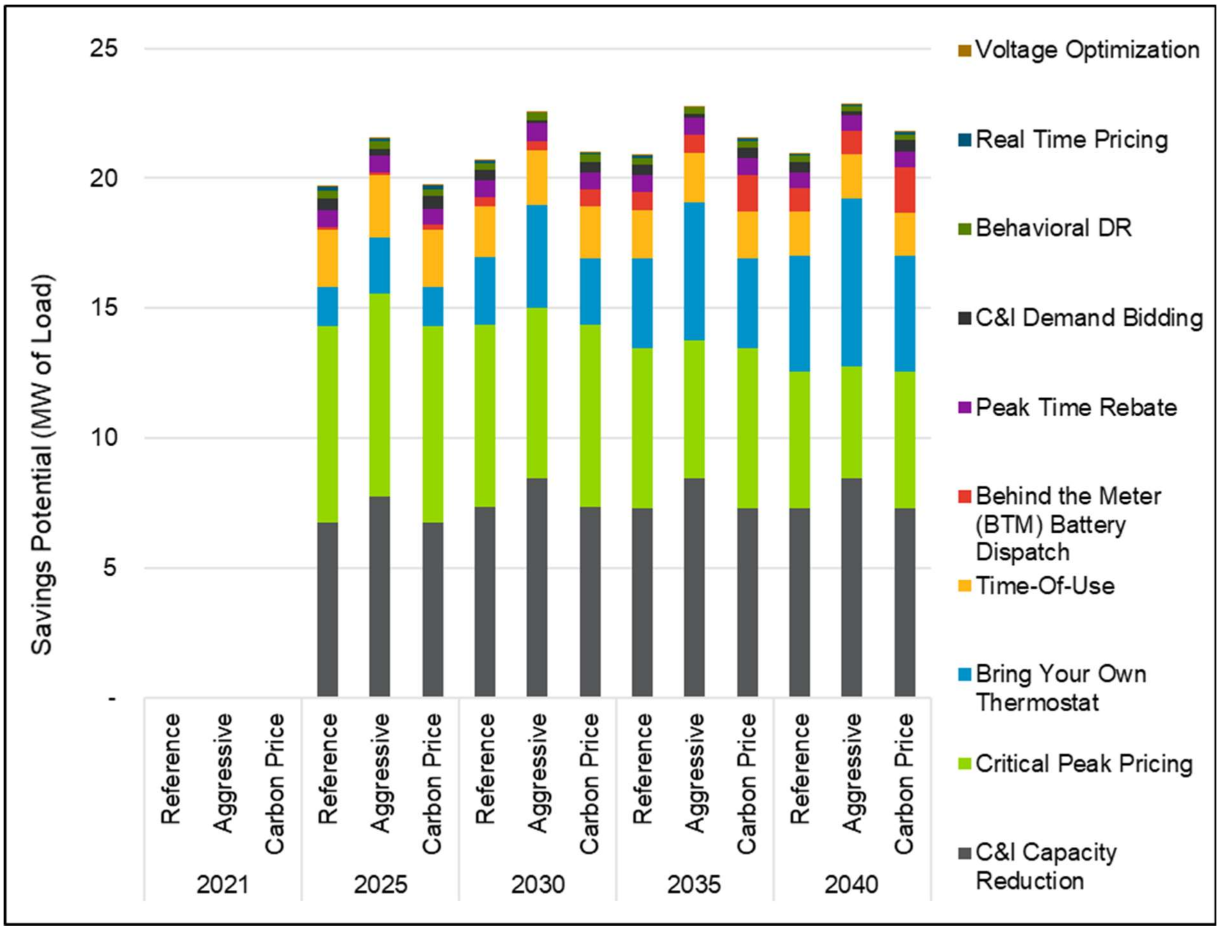
Figure ES-5. Lower Peninsula Electric Summer Achievable Potential by DR Option and Scenario (% of Peak Demand)



Source: Guidehouse analysis

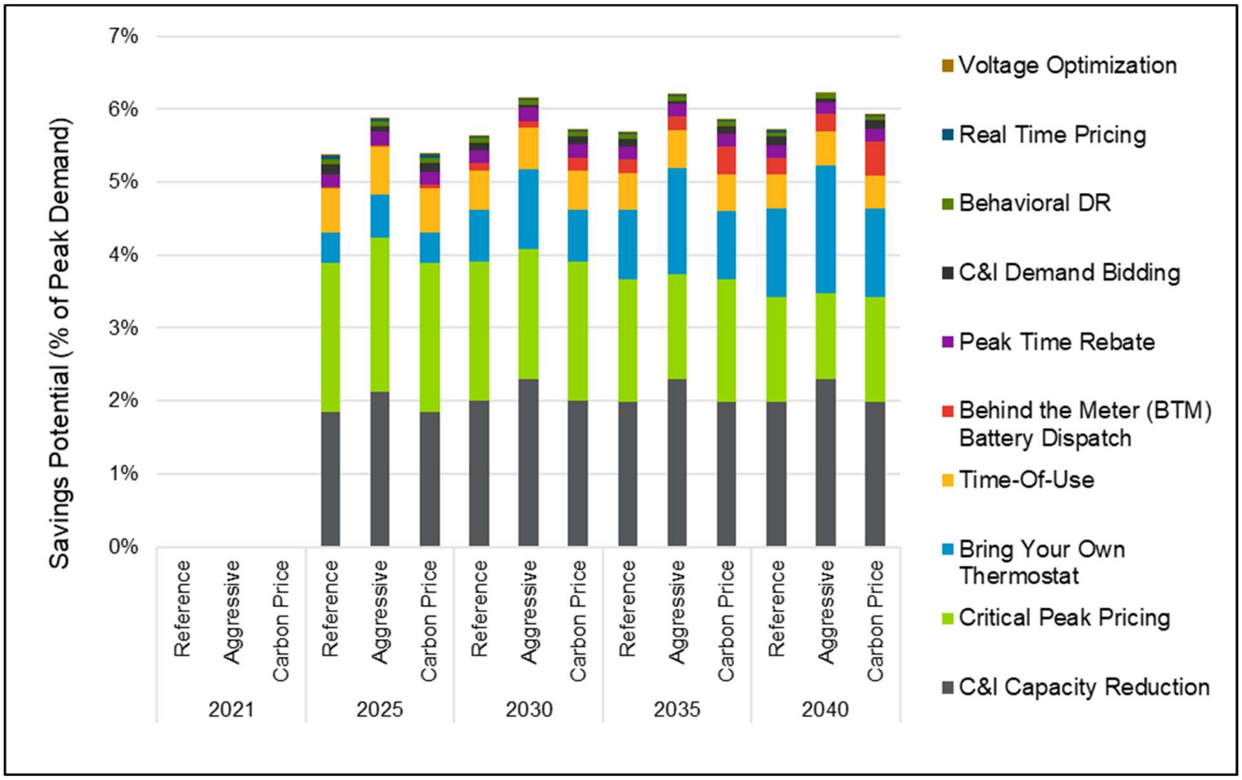
Figure ES-6 shows the MW breakdown of the Upper Peninsula achievable potential by DR option for selected years, and Figure ES-7 shows the achievable potential as a percentage of the participating utilities' peak demand. The achievable potential increases steadily from around 3 MW of summer peak reduction potential in 2022 (translates to around 1% reduction in summer peak demand forecast in 2022 for the Lower Peninsula) to over 20 MW in 2040 (translates to around 6% reduction in summer peak demand forecast in 2040 for the Upper Peninsula). The top three DR options that constitute over 80% of the total cost-effective potential are – C&I Capacity Reduction, CPP, and BYOT. Unlike the Lower Peninsula, DLC-switch is not cost-effective for the Upper Peninsula. Regarding the scenario comparisons, the trends discussed for the Lower Peninsula potential apply. Unlike the Lower Peninsula, there are no changes in cost-effectiveness screening for the Upper Peninsula between Reference and Aggressive Scenarios.

Figure ES-6. Upper Peninsula Electric Summer Achievable Potential by DR Option and Scenario (MW at Meter)



Source: Guidehouse analysis

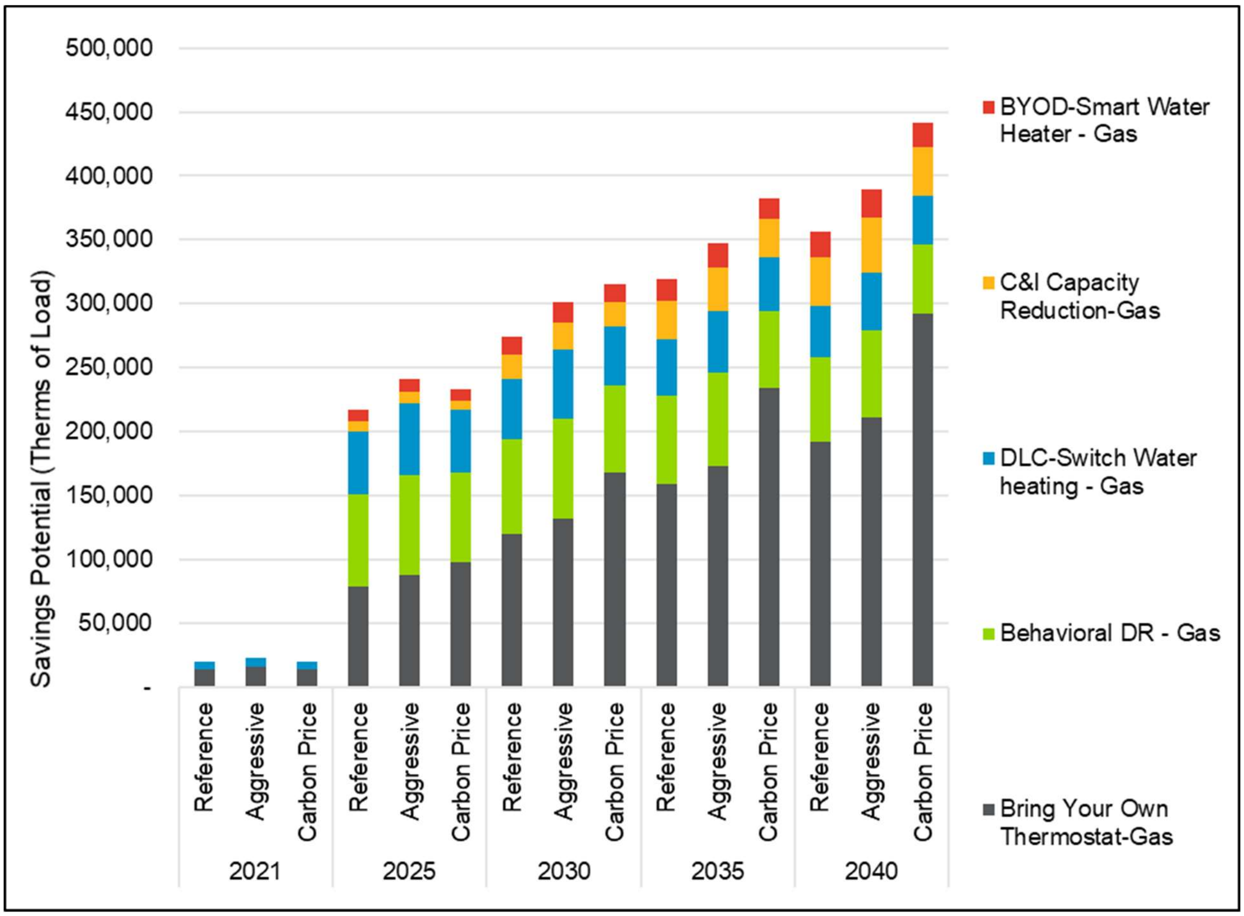
Figure ES-7. Upper Peninsula Electric Summer Achievable Potential by DR Option and Scenario (% of Peak)



Source: Guidehouse analysis

Figure ES-8 shows the MW breakdown of the Lower Peninsula natural gas potential by DR option for selected years. The Reference Scenario natural gas DR potential for the Lower Peninsula is projected to significantly grow from around 20,000 therms in 2021 to roughly 356,600 therms in 2040. DLC-switch water heating and BYOT are the only options in 2021, with DLC contributing 6,178 therms out of a total 20,0000 therms (31% share). In 2040, BYOT has the largest achievable potential in the Lower Peninsula with 192,435 therms (54%), with Behavioral DR second highest at around 20% share in total. The Aggressive Scenario potential is around 10% higher than the Reference Scenario potential, driven by higher incentives and consequently higher participation levels in DR programs. The Carbon Price Scenario potential results are almost 20% higher than the Reference Scenario results. This increase in potential is primarily driven by higher potential from the BYOT program offer for gas, which in turn is due to greater adoption of smart thermostats in the Carbon Price Scenario than the Reference Scenario.

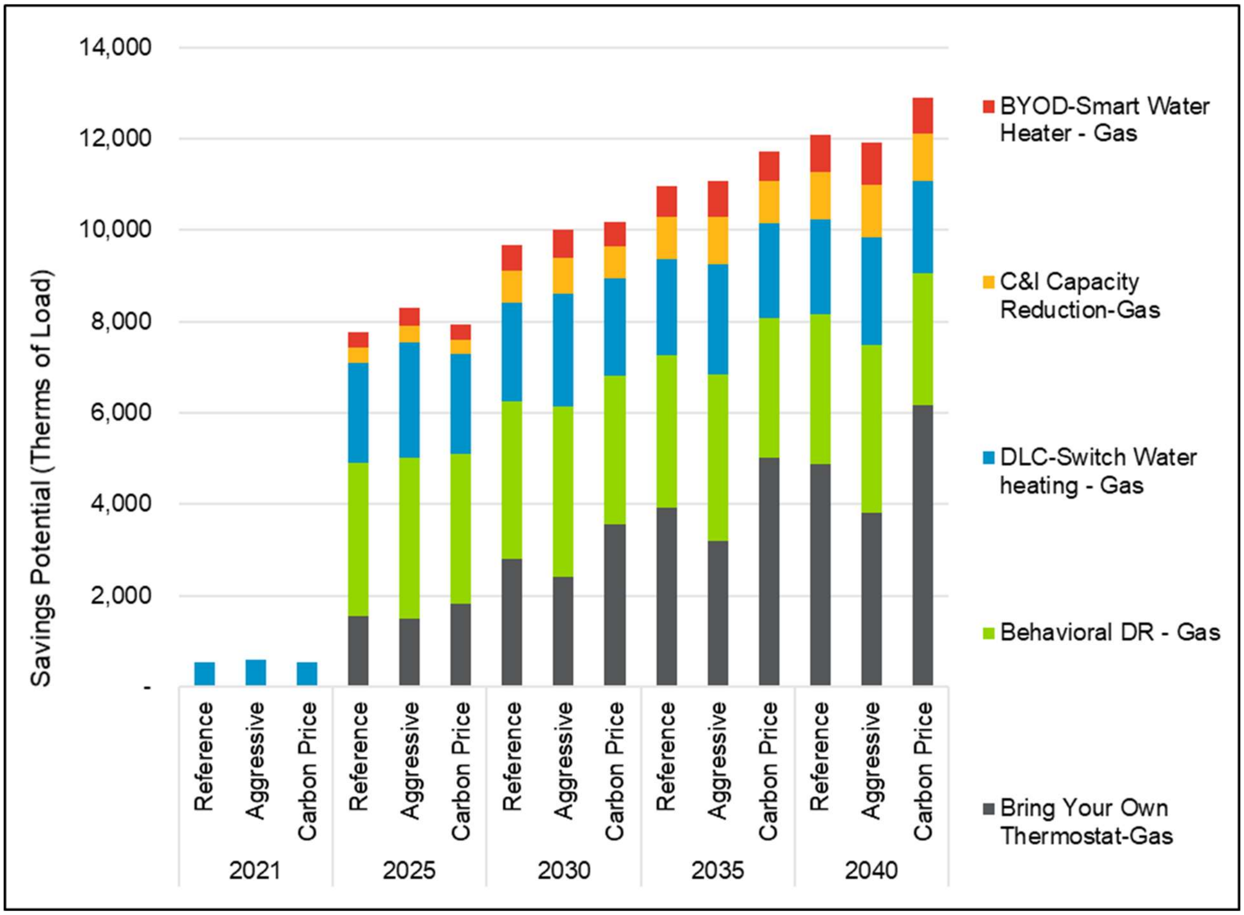
Figure ES-8. Lower Peninsula Natural Gas Winter Achievable Potential by DR Option and Scenario (therms at Meter)



Source: Guidehouse analysis

Figure ES-9 shows the MW breakdown of the Upper Peninsula natural gas potential by DR option for selected years. The trends for the Upper Peninsula are similar to those for the Lower Peninsula. The Upper Peninsula Reference Scenario potential is 12,086 therms in 2040. Majority of the contribution is from BYOT and Behavioral DR for gas. The increase in energy efficiency potential and differences in smart thermostat adoption in the Aggressive Scenario leads to slightly lower potential in the later years compared to the Reference Scenario. The higher potential in the Carbon Price Scenario than the Reference Scenario is primarily due to greater potential from the BYOT option for gas

Figure ES-9. Upper Peninsula Natural Gas Winter Achievable Potential by DR Option and Scenario (therms at Meter)



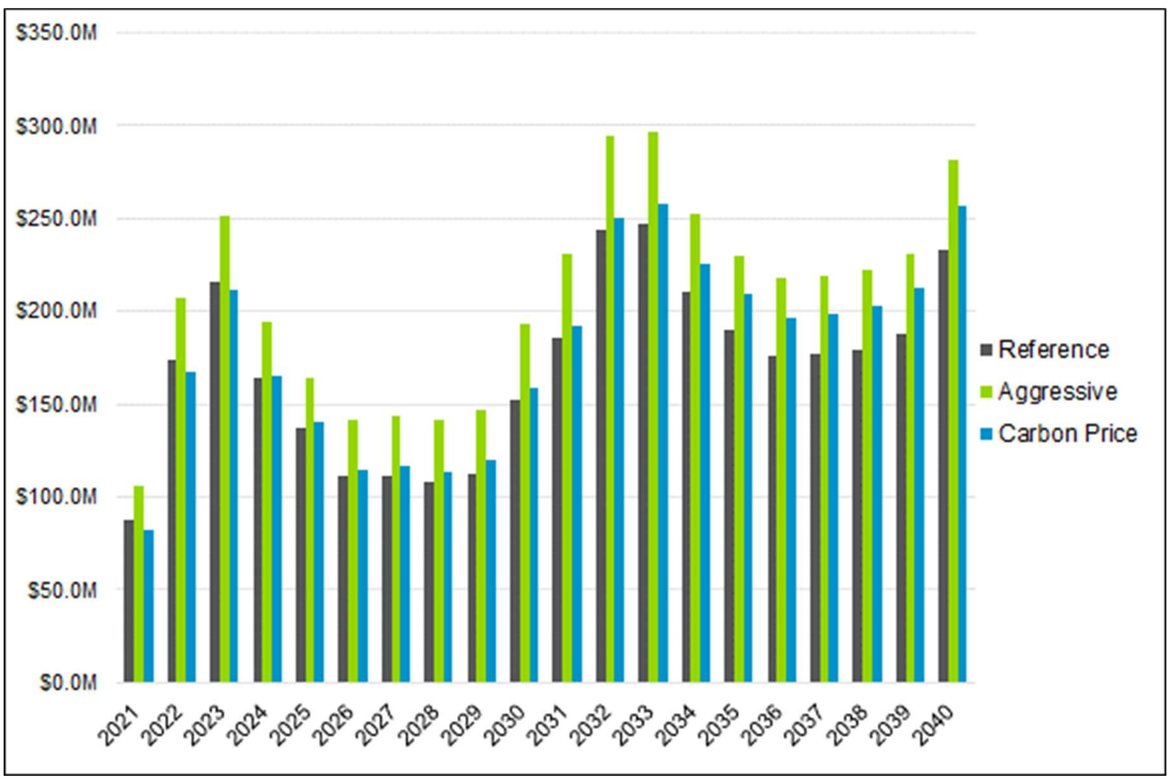
Source: Guidehouse analysis

Annual Costs Results

Figure ES-10 shows the estimated annual costs for the Lower Peninsula DR program portfolio across the three scenarios. These costs represent the total annual costs Michigan utilities are likely to incur to realize the potential values discussed previously and include a combination of different types of fixed and variable costs, either incurred one time or on a recurring basis, for implementing the DR programs (refer to Section 2 for a description of the different types of costs). The cyclical nature of the annual costs over the analysis timeframe is due to the fact that the costs grow in the initial years while the program is ramping up as the programs incur enabling technology costs (e.g., DLC-switch, CPP with enabling technology) and customer marketing and recruitment costs during the ramp up stage. Once the programs mature and the participation levels off, these one-time variable costs are no longer incurred and therefore the annual program costs level off. At that stage, the annual costs primarily consist of incentive payments to customers, O&M costs, and annual program administration costs. However, program development costs and technology enablement costs are reincurred at the end of the program life and technology life, respectively, and this trend leads to the increased costs during the 2030-2032 timeframe, and the 2040 timeframe.

Costs are higher for the Aggressive Scenario compared to the Reference Scenario due to the higher incentives paid to customers, additional marketing and outreach, higher technology enablement costs, and the higher operation and maintenance (O&M) costs incurred because of higher customer enrollment in these scenarios. The Carbon Price Scenario has higher costs due to higher enabling technology adoption, namely smart thermostats, EVs, and batteries.

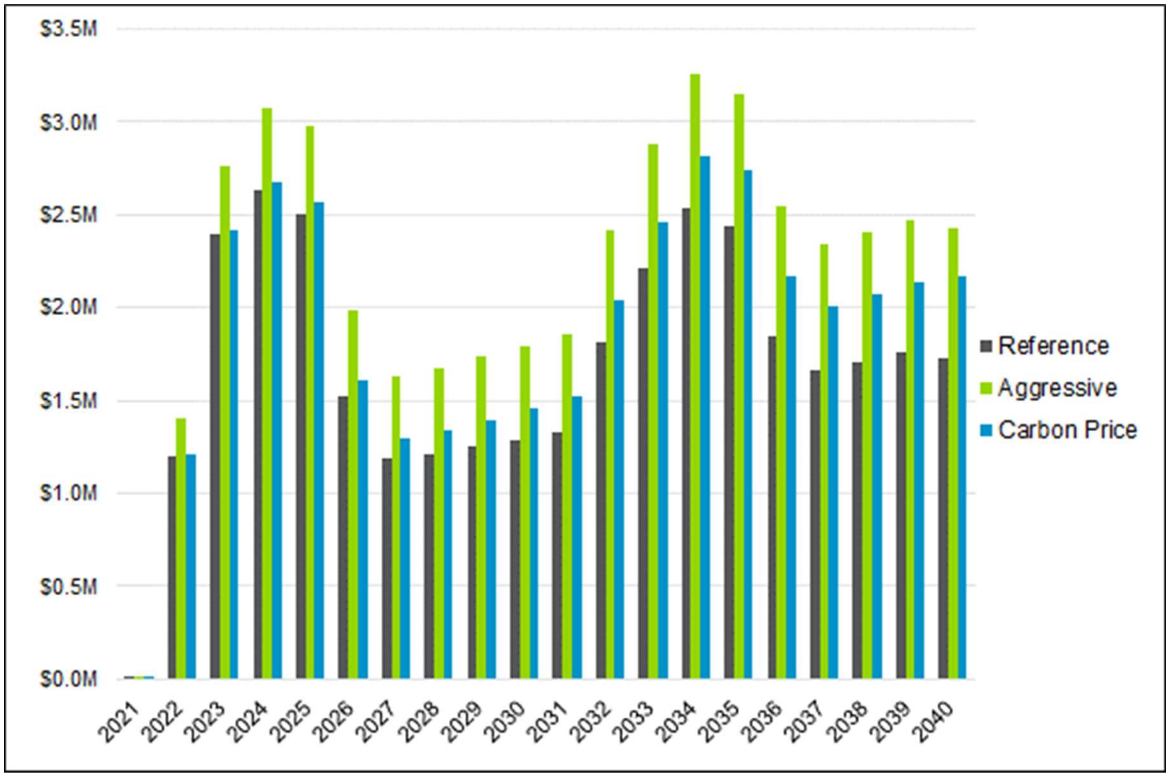
Figure ES-10. Lower Peninsula Annual Electric DR Portfolio Costs by Scenarios



Source: Guidehouse analysis

Figure ES-11 shows the estimated annual costs for the Upper Peninsula DR program portfolio across the three scenarios, which show similar trends as those for the Lower Peninsula.

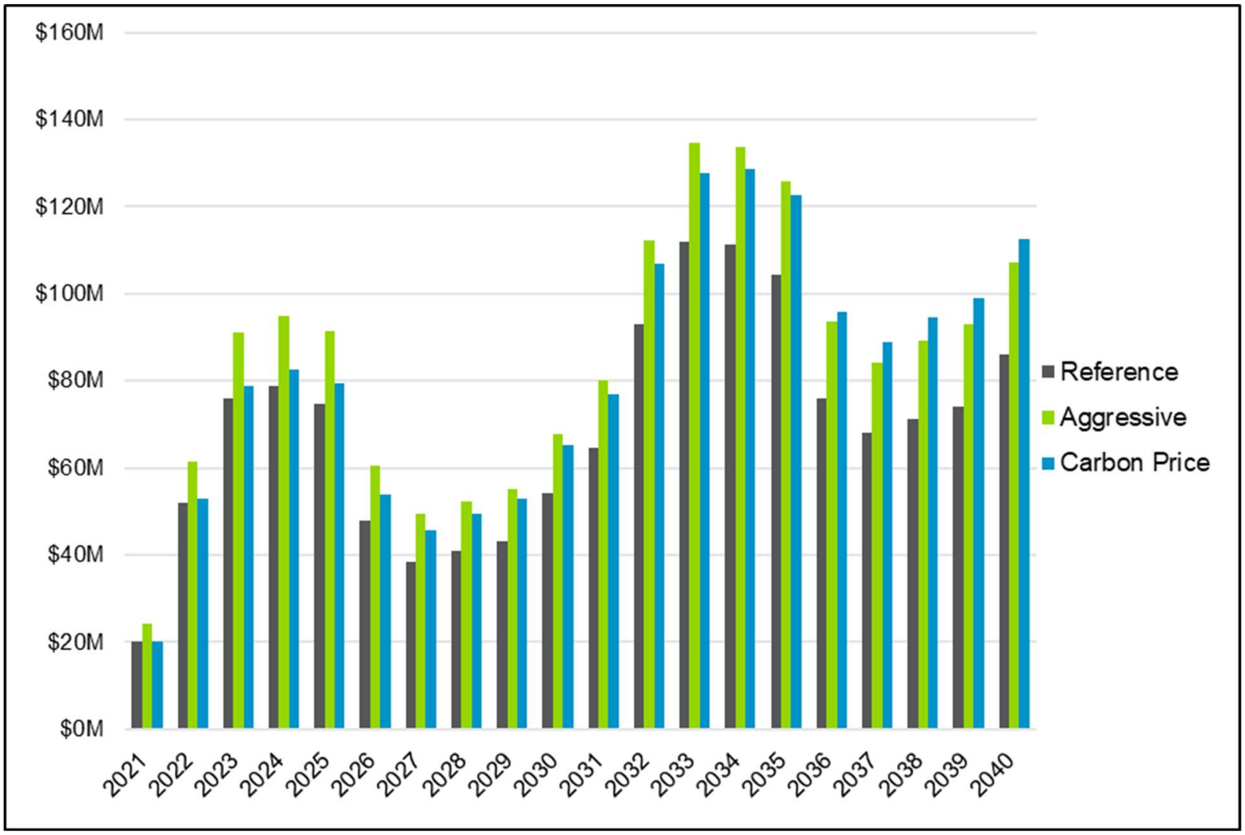
Figure ES-11. Upper Peninsula Annual Electric DR Portfolio Costs by Scenarios



Source: Guidehouse analysis

Figure ES-12 shows the estimated annual costs for the Lower Peninsula DR natural gas program portfolio across the three scenarios. The Aggressive Scenario has the highest costs for the first 15 years due to the increased incentives in this scenario. The Carbon Price Scenario consistently has higher costs compared to the Reference Scenario and has the highest costs of all scenarios during the last few years of the study; this is primarily driven by the increased adoption of smart thermostats eligible for BYOT, which leads to a growth in the program.

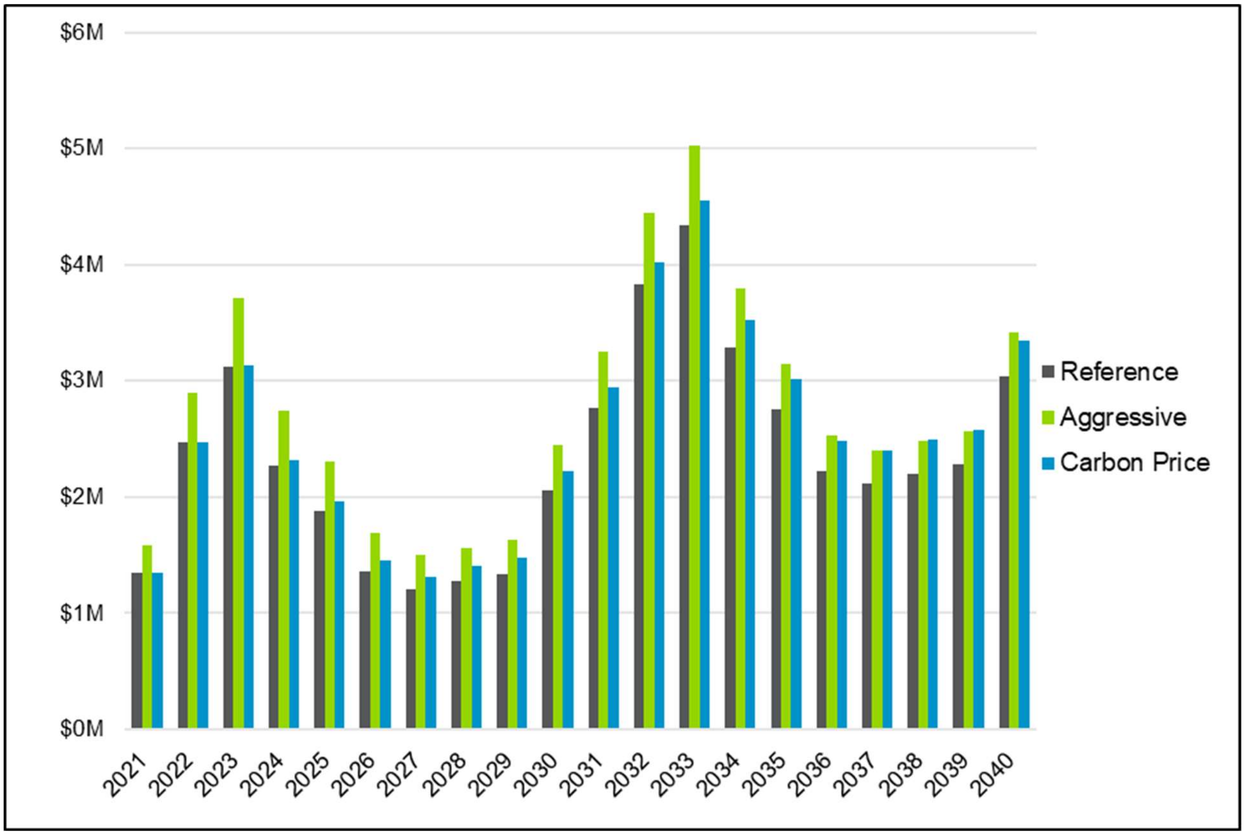
Figure ES-12. Lower Peninsula Gas Annual DR Portfolio Costs by Scenario



Source: Guidehouse analysis

Figure ES-13 shows the estimated annual costs for the Upper Peninsula DR natural gas program portfolio across the three scenarios. The trends discussed for the Lower Peninsula apply to the Upper Peninsula.

Figure ES-13. Upper Peninsula Natural Gas Annual DR Portfolio Costs by Scenario



Source: Guidehouse analysis

Conclusions

The DR potential study results presented in this report assess both summer and winter peak electric demand reduction potential, and winter natural gas DR potential. The study incorporated the latest market data on customer characteristics and DR program performance from the Michigan utilities, and primary research (customer surveys) conducted to assess customer awareness of and willingness to enroll in different DR program types. The residential and C&I customer surveys provided valuable information to help inform the likelihood of customers participating in different DR program types. The DR study considered interactions resulting from the EWR study and incorporated baseline adjustments from the EWR analysis to project baseline peak demand, net of EWR savings, for assessing DR potential. In addition to the baseline adjustments, the study incorporated EWR-DR integration in modeling customer adoption of technologies that provide EWR and DR co-benefits (e.g., smart thermostats), which provide useful insights on EWR and DR value stacking for the customer. Following are the key findings and takeaways from the DR potential analysis:

- **Electric DR Achievable Potential Trends:** The statewide electric DR achievable potential is expected to grow substantially over the 2021-2040 timeframe. The summer peak electric demand reduction for the Lower Peninsula is expected to grow to about 10% of summer peak in the long-term, from 2% to 3% in the initial years (projected to grow from around 300 MW to 1,850 MW over the 20-year timeframe). The Upper Peninsula long-term summer electric DR achievable potential is projected to achieve around 6% reduction in peak demand (projected to grow from around 3 MW to 20 MW over the 20-year timeframe). The top four DR options that constitute over 80% of the total cost-effective potential are – C&I Capacity Reduction, Bring Your Own Thermostat (BYOT) program, Critical Peak Pricing (CPP), and Direct Load Control-Switch. Advanced DR options, such as EV Managed Charging and BTM Battery Dispatch, grow steadily over time as adoption of these technologies increases.

- **Natural Gas DR Achievable Potential Trends:** The statewide natural gas DR achievable potential too is expected to grow substantially over the 20-year study timeframe. The total natural gas DR achievable potential for the Lower Peninsula is projected to grow from around 20,000 therms to more than 350,000 therms over the 20-year timeframe. The Upper Peninsula natural gas achievable potential is projected to grow from less than 2,000 therms to around 12,000 therms over the 20-year timeframe. More than 50% of the total savings are derived from the BYOT program option. Behavioral DR for residential and the C&I Capacity Reduction option for natural gas are the other major contributors toward natural gas potential.

- **EWR-DR Integration Benefits:** The study findings highlight the benefits of EWR-DR integration when considering customer adoption of technologies that provide EWR and DR benefits from a joint perspective. Integration of EWR and DR incentives in customer adoption leads to a significant increase in the potential from technologies that provide EWR and DR co-benefits. This is clearly illustrated through the enhanced adoption of technologies such as smart thermostats and Energy Management Systems (EMS) through the lowering of the customer payback period that leads to enhanced adoption when EWR and DR incentives are combined in customer decision-making to adopt these technologies. This result emphasizes the importance of EWR and DR value stacking in presenting integrated demand-side management (IDSM) program offerings to customers.

- **Customer Segment Contribution in Total Achievable Potential:** Residential customers in aggregate across all segments have more than a 60% share of the electric DR achievable potential for the Lower Peninsula, with the highest contribution from non-low income single-family customers. Out of the remaining 40% from the C&I sector, extra-large C&I customers have the highest contribution. Upper Peninsula electric DR achievable potential has an approximately equal contribution from residential and C&I customers, with single-family residential customers and extra-large C&I customers having highest share in achievable potential. For natural gas, more than 80% of the total DR achievable potential is derived from residential customers.

- **Bring Your Own Thermostat (BYOT) Potential Trends:** BYOT potential is projected to increase steadily with growth in adoption of smart thermostats. The adoption of smart thermostats is considered from an integrated EWR-DR standpoint where a customer factors in both EWR rebates and DR incentives in decision making to purchase a smart thermostat, which leads to a lowering of payback period (as compared to EWR rebate consideration only) and leads to greater adoption of the technology. BYOT potential significantly increases over time for both electric and natural gas for residential customers primarily, although it applies to small and medium C&I customers as well (growth in BYOT potential is shown in the C&I potential results too).

- **C&I Potential Trends:** The contribution from C&I customers is primarily from the C&I Capacity Reduction program which is currently offered by Michigan utilities and is widely offered by many other utilities. A substantial portion of this could potentially be derived from extra-large C&I customers where the controlled end-use depends on the facility type. The upward trend in C&I DR potential is also associated with increased adoption of technologies that provide dual EWR and DR benefits to the customers such as EMS and advanced lighting controls. Similar to smart thermostats, consideration of both EWR and DR incentives in customer decision-making to purchase these technologies leads to a lowering of the payback period, and thereby increased adoption of these technologies.

- **Cost-effectiveness of DR Options:** A majority of the DR options considered in the analysis are cost-effective under the avoided cost assumptions provided by the Michigan utilities. Among the top potential contributors, C&I Capacity Reduction and Critical Peak Pricing are highly cost-effective with UCT benefit-cost ratios of greater than 3.0. BYOT has significant contribution toward potential but has higher costs than C&I Capacity Reduction and CPP. The DLC-switch option has higher costs than BYOT due to enabling technology costs. It passes cost-effectiveness screening with a 0.8 UCT threshold for the Lower Peninsula but is not cost-effective for the Upper Peninsula. Advanced DR options such as BTM Battery Dispatch are cost-effective for both regions. However, EV Managed Charging passes cost-effectiveness for the Lower Peninsula but not for the Upper Peninsula

- **Scenario Results:** The Aggressive Scenario Results show higher achievable potential than the Reference Scenario due to higher incentive assumptions, and consequently higher participation in DR programs, even though a few DR options are no longer cost-effective under the Aggressive Scenario due to higher costs. The DR analysis Aggressive Scenario incorporates higher adoption of technologies that provide EWR and DR benefits from the EWR analysis, which is also reflected in the Aggressive Scenario results. The Carbon Price Scenario projects slightly greater DR achievable potential than the Reference Scenario, due to higher battery and EV projected participation. Additionally, greater adoption of EWR-DR technologies such as smart thermostats in the Carbon Price Scenario than the Reference Scenario leads to higher achievable potential associated with those technologies.

1. Introduction

The Michigan Public Service Commission (MPSC) engaged Guidehouse Inc. (Guidehouse) to prepare a demand response (DR) potential assessment across the State of Michigan from 2021 to 2040. The DR potential study was conducted in conjunction with the energy waste reduction (EWR) potential study conducted by Guidehouse for the MPSC. The objective of the DR potential assessment was to estimate the potential for cost-effective DR as a capacity resource to reduce customer loads during peak summer periods. Additionally, the study assessed electric winter peak reduction potential plus natural gas DR potential. Guidehouse developed these potential estimates for the Lower Peninsula and the Upper Peninsula.[4]

As is typical in the development of such studies, Guidehouse worked collaboratively with the MPSC and its stakeholders to ensure the study reflects current Michigan market conditions. We received considerable guidance and feedback from MPSC staff, particularly in the development of global input assumptions, measure characterizations, and historical portfolio performance calibration. Guidehouse also carefully considered, and as appropriate, was responsive to stakeholders' input, incorporating their feedback into the analysis approach.

Guidehouse worked with the MPSC and collaborated with the Michigan utilities to identify relevant DR program types in participating utility service territories and the applicability of these program types by customer segments and end uses to realize demand reductions. Guidehouse developed achievable potential estimates for different DR program and measure types at various levels of disaggregation and the associated costs for implementation of a DR program portfolio. The DR technology and program types included in the assessment represent what Michigan utilities currently offer and could potentially offer. The assessment covered a wide spectrum of program and enabling technologies for DR and included different types of controls for curtailing load at customer premises that included conventional and advanced control methods. Guidehouse estimated annual and levelized costs and conducted cost-effectiveness assessment of the DR options included in the assessment to represent the potential from cost-effective DR options.

1.1 Stakeholder Engagement and Interactive Review Process

The stakeholder engagement process and level of participation in Michigan was greater than what Guidehouse has seen in many other jurisdictions. We appreciate the thorough review and comments provided by stakeholders and thank them for their feedback and participation in the process. Modifications related to feedback from the reviews were incorporated into this final report.

Three virtual stakeholder meetings were conducted using the Microsoft Teams platform. Each meeting provided an update of study progress and provided stakeholders the opportunity to ask questions. Guidehouse used a project-specific email address to receive study-specific feedback from stakeholders.

- **December 2, 2020:** The initial stakeholder meeting provided an overview of the potential study approach and summarized the project's status. The meeting also solicited stakeholder feedback on the EWR measure and DR option lists.

[4] The Excel results file accompanying this report provides results disaggregated by utility.

- **February 4, 2021:** The second stakeholder meeting provided a general project update. Guidehouse presented on, and solicited feedback to, the market characterization results, and provided an overview of stakeholder feedback from the draft customer survey instruments.
- **June 17, 2021:** The final stakeholder meeting included a presentation of the EWR and DR achievable potential study draft results and provided stakeholders an opportunity to provide feedback and request clarifications on the analysis and results. Questions and clarifications from the meeting were incorporated into this final report.

Key reviews occurred and stakeholder feedback was incorporated into the Research Plan, measure list, customer survey, global inputs/market characterization, and draft technical, economic, and achievable potential.

This study began in September 2020 and encompassed five phases. Each phase involved interactive engagement and review.

- **Research Plan.** The Research Plan details how Guidehouse planned to gather and analyze project data and model the estimated potentials. The Research Plan summarized planned stakeholder engagement, our process for drafting and finalizing the reports, and included the project's planned schedule and assumptions.
- **DR Options list.** Guidehouse compiled a comprehensive list of DR options based on historical Michigan program data and an assortment of recent potential studies in comparable jurisdictions and based on our team's collective knowledge and expertise in the area. We developed savings and cost assumptions based on program data provided by Michigan utilities, wherever available, and filled in gaps with relevant data and information from Guidehouse's experience in conducting similar studies in other jurisdictions. The DR options list was provided for review to stakeholders and finalized based on stakeholder feedback.
- **Customer surveys.** Survey objectives included assessing customer awareness of and willingness to enroll in DR programs currently offered by Michigan utilities, as well as potentially new programs and rates that utilities could offer and incorporated the effect of the COVID-19 pandemic to inform modeling. The surveys provided information on current level of awareness of DR programs and customer likelihood to enroll in DR programs under varying levels of incentives. Additionally, the surveys asked questions to help inform customer willingness to adopt technologies that provide both EWR and DR benefits (e.g., smart thermostats, networked LEDs, smart water heaters).
- **Market characterization.** Several rounds of data requests and review were conducted from the applicable Michigan utilities to inform the market characterization. The information received through the data request was used as the preferred source for model inputs. Secondary sources, such as US Census Bureau (Census) data, FERC Form-1 data, and US Energy Information Administration (EIA) data, were used to estimate statewide input values after utility data gaps were identified. Input values were adjusted throughout the study period as new data and resulting modifications to the modeling methodology became relevant.
- **Draft potential results**. Guidehouse presented draft potential results to stakeholders on June 17, 2021 and incorporated their feedback to develop the final potential results.

1.2 Utilities

Guidehouse engaged with Michigan utilities at various stages through the course of the study. The utilities provided customer and load data required for market characterization, DR program information, and customer contact information to conduct online residential and commercial and industrial (C&I) customer surveys to help inform customer adoption projections in the potential model. We received data from the following utilities:

- Alpena Power Company (electric)
- Consumers Energy (gas and electric)
- DTE Energy (gas and electric)
- Indiana Michigan Power (I&M) (electric)
- Michigan Gas Utilities (MGU) (gas)
- Northern States Power (NSP) (gas and electric)
- SEMCO Energy Gas Company (gas and electric)
- Upper Michigan Energy Resources Corporation (UMERC) (gas and electric)
- Upper Peninsula Power Company (UPPCO) (electric)

Unless otherwise specified, all utilities will be referred to jointly in this report.

1.3 Report Organization

The report is organized as follows:

- Section 2 describes the analysis approach and framework used to estimate the DR potential, including market characterization and baseline peak demand projections for DR potential assessment, and characterization of DR options. Section 2 also summarizes Guidehouse's primary data collection approach and results through the online customer surveys

- Section 3 presents the DR potential results for the Lower Peninsula and Upper Peninsula for both electric and natural gas. Electric includes both summer and winter peak reduction. The results are presented in aggregate and at various levels of granularity. This section also reports annual and levelized costs by DR options and cost-effectiveness results.

- Section 4 presents the study conclusions.

The report also includes four appendices:

- Appendix A. Residential Survey Instrument

- Appendix B. Commercial & Industrial Survey Instrument

- Appendix C. Technical Potential Results

- Appendix D. DR Potential Assessment Results File

Guidehouse also provided the MPSC with the inputs database, which includes all data used to model the DR potential and cost estimates, and an additional database that includes all the potential and cost results from this analysis.

2. Demand Response Potential Assessment Methodology

This section describes the approach for developing the DR potential and cost estimates and for conducting the cost-effectiveness assessment. Guidehouse worked with MPSC and the Michigan utilities to represent relevant DR programs and enabling technologies that utilities currently offer or could potentially offer to realize summer peak demand reductions. The study additionally electric winter peak demand reduction potential from the DR options and separately assessed natural gas DR potential.

Guidehouse developed DR potential and cost estimates using a bottom-up analysis. The analysis uses a combination of primary data (e.g., market and DR program data from Michigan utilities) and relevant secondary sources to develop data inputs required for assessing DR potential and cost-effectiveness. These data inputs feed into Guidehouse's DRSim™ model, customized for the study, which produces DR potential, annual program costs, and cost-effectiveness of DR options at various levels of disaggregation.

The following subsections describe the approach for DR potential estimation and cost-effectiveness assessment which consists of the following steps (summarized in Figure 2-1):

1. **Undertake market characterization** for DR potential assessment
2. **Develop baseline projections** (customer count and coincident peak demand) over the study period (2021-2040)
3. **Define and characterize DR options** and map applicable options to relevant customer classes and/or building types
4. **Develop programmatic assumptions**, which include participation, unit load reductions, and cost assumptions
5. **Estimate potential, annual costs, levelized costs and cost-effectiveness** by DR option, customer class and building type
6. **Conduct scenario analysis** and present DR potentials, annual costs, and cost-effectiveness results by scenario

Figure 2-1. DR Potential Assessment Steps

Step 1: Market Characterization	Characterize market for DR potential estimation: Segment market for DR potential assessment and develop number of customers and coincident peak load estimates by segment for base year.
Step 2: Develop Baseline Projections	Define peak and develop baseline peak demand projections over the study period (2021-2040).
Step 3: Define DR Options	Define and characterize DR options and associated enabling technologies and map applicable options to relevant customer classes.
Step 4: Define Key Assumptions for Potential and Costs	Develop assumptions for participation, unit load reduction, and itemized costs for each DR option.
Step 5: Estimate Potential, Costs, and Cost-effectiveness	Present potential estimates, annual costs, levelized costs, and assess cost-effectiveness of DR options.
Step 6: Undertake Scenario Analysis	Present potential results by scenario, which consider baseline adjustments, and participation scenarios with varying incentives.

Source: Guidehouse analysis

2.1 Market Characterization for DR Potential Assessment

Market characterization is the first step in the DR potential assessment process. The segmentation of residential customers is based on the approach followed in the EWR potential study conducted by Guidehouse in conjunction with the DR potential study. The segmentation of C&I customers is based on maximum demand values, which were developed using the participating Michigan utilities' rate schedules, retail sales and demand data. Table 2-1 summarizes the market segmentation approach for DR potential assessment.

Table 2-1. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: By Sector	• Residential • Commercial and Industrial (C&I)
Level 2: By Customer Segment	• Residential – Single-family – Multifamily – Single-family Low Income – Multifamily Low Income • Electric C&I customers by size, based on maximum demand values[5]: – Small C&I (< 30 kW) – Medium C&I (30-200 kW) – Large C&I (201-1000 kW) – Extra-Large C&I (>1000 kW) • Gas C&I customers by annual consumption – Small C&I (<14,000 therms) – Large C&I (≥14,000 therms)
Level 3: By Region	• Lower Peninsula Electric • Upper Peninsula Electric • Lower Peninsula Natural Gas • Upper Peninsula Natural Gas

Source: Guidehouse analysis

Level 1: Sector

Guidehouse segmented customers between the residential and C&I sectors.

Level 2: Customer Segment

For the residential sector, segmentation to disaggregate sector-level data into dwelling type and income level segments was developed as part of the EWR market characterization, and was directly used in the DR baseline development for both electricity and natural gas. These splits were developed using statewide census data on the fraction of housing types (single-family vs. multifamily) and percentage of income-eligible customers.[6]

For the electric C&I sector segmentation, disaggregated peak data at the rate code level was mapped to customer count data by rate code or tariff type using utility data, or data from FERC Form 1. Then, the average per customer peak demand was calculated for each rate code, which was then used to assign each C&I rate to a segment based on the demand cutoffs shown in Table 2-1. In cases where utility-specific data was unavailable to estimate annual peak demand values from annual energy, load factors from other similar utilities were applied.

[5] The segmentation by size for DR and EWR is different. The size segmentation for DR is based on the type of end-use control technology and the type of DR program offer. The demand thresholds presented here for segmentation by size is typically what is considered for DR potential studies.
[6] Defined as percent of households below 200% of the federal poverty line

Like the EWR natural gas sales forecast, the natural gas C&I sector segmentation was defined to align the Small C&I and Large C&I segments with DTE's GS-1 and GS-2 gas rate schedules. These schedules have an implicit break-even point of 14,000 therms or $49,300 in natural gas energy costs per year, and were applied to the other Michigan utilities. The Medium C&I and Extra-Large C&I segments were not used for natural gas market characterization.

Level 3: Region

Guidehouse characterized the baseline projections and DR options separately for each region by parsing utility data by Lower and Upper Peninsula regions and fuel type.

2.2 Baseline Projections for DR Potential Assessment

The next step after market segmentation was to develop baseline projections for the number of accounts and associated peak demand by customer segment over the potential analysis period (2021-2040). The baseline account and peak demand projections for the DR potential assessment were developed at the following levels:

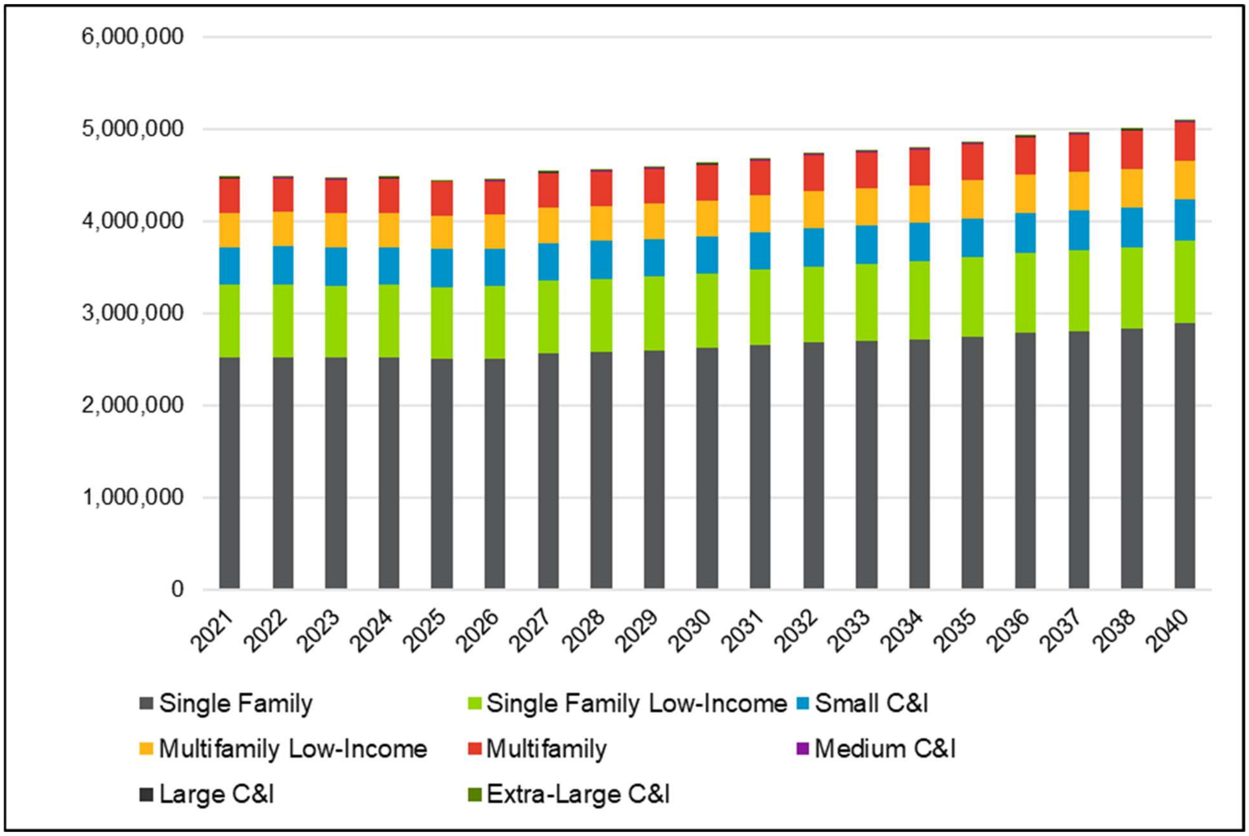
- Account count
    - Region
    - Fuel type
    - Customer segment
- Peak demand projections
    - Season
    - Region
    - Fuel type
    - Customer segment
    - End use

2.2.1 Account Count Projections

First, Guidehouse developed a forecast of the number of accounts by region, fuel type, and customer segment. For the residential sector, Guidehouse could directly use the counts developed as part of the EWR market characterization. For the C&I sector, Guidehouse did not follow the segmentation in the EWR study since the account counts developed for the EWR potential estimation did not have the required classification by size needed for the DR analysis. Where available, Guidehouse directly used base year account counts and forecasts from Michigan utility-specific data. When account counts for only a subset of years were available from Michigan utilities, Guidehouse forecasted the account counts using the annual growth in the sales forecast, which was developed as part of EWR market characterization. When no utility account count data was provided, supplemental FERC Form-1 and EIA-861 data was used to estimate the number of accounts.

Figure 2-2 summarizes electric account count projections by customer segment for the Lower Peninsula. Regular single-family customers constitute over 50% of the total counts followed by single-family low income at less than 20%. Regular multifamily and multifamily low income customers constitute less than 10% each of the total accounts. Among C&I customers, small C&I accounts constitute slightly less than 10% of the total accounts. Medium, large, and extra-large C&I segments constitute less than 1% of the total accounts.

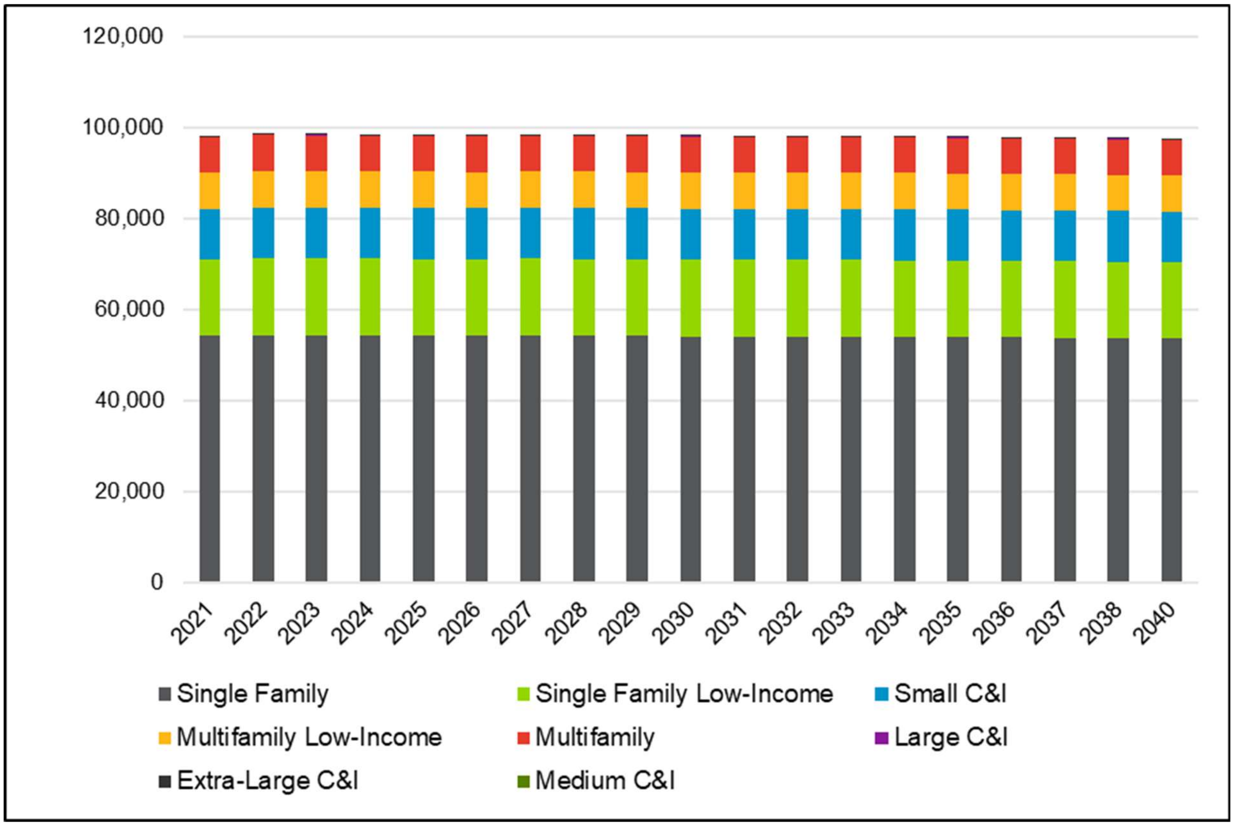
Figure 2-2. Lower Peninsula Electric Account Projections by Customer Segment



Source: Guidehouse analysis

Figure 2-3 summarizes the electric account count projections by customer segment for the Upper Peninsula. The customer segment shares in the account count is similar to the Lower Peninsula, with regular single-family at greater than 50% share, followed by single-family low income at around 15% share. Regular multifamily and multifamily low income are at less than 10% share each. Small C&I customers have approximately 10% share in total count. Medium, large, and extra-large C&I customers have less than a 0.5% share of the total account count.

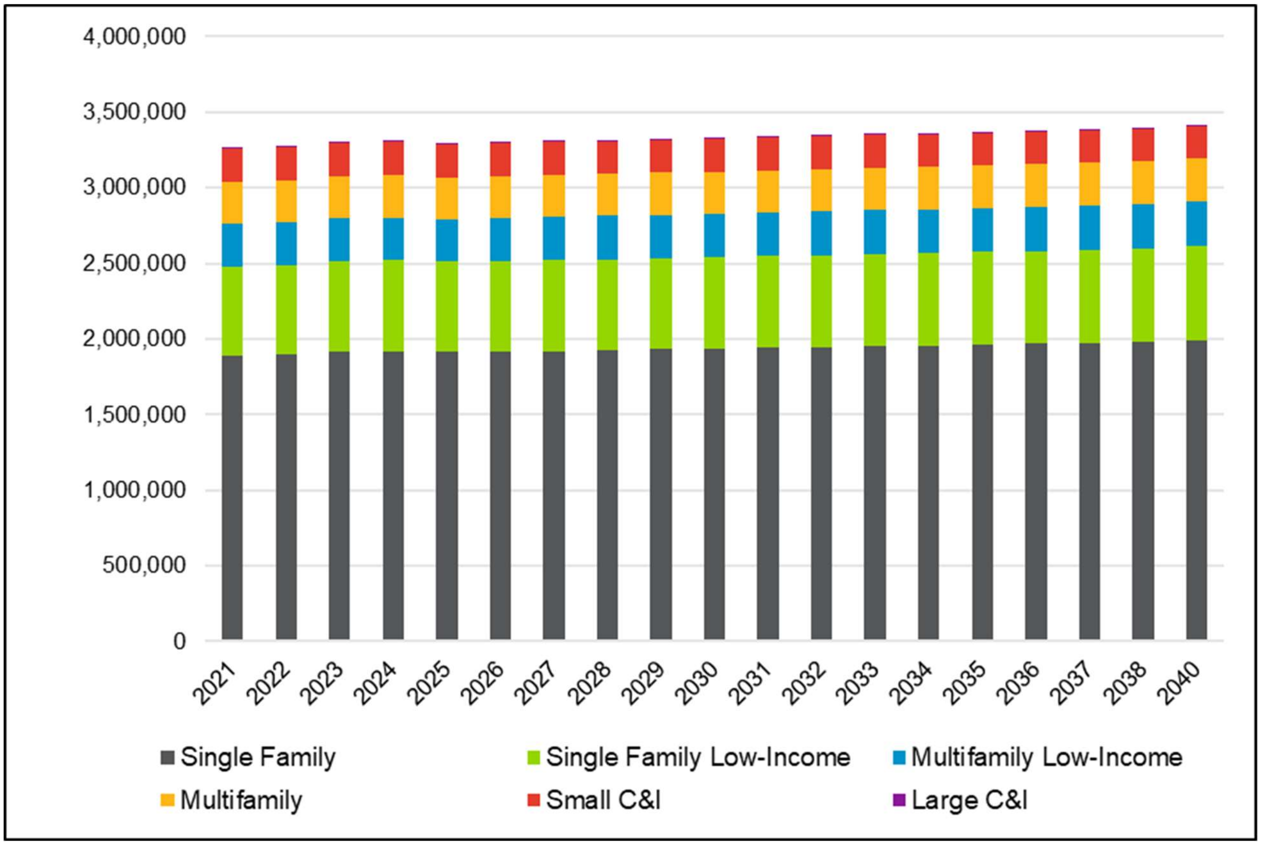
Figure 2-3. Upper Peninsula Electric Account Projections by Customer Segment



Source: Guidehouse analysis

Figure 2-4 summarizes the account count projections by customer segment and region for natural gas regions. The forecast is developed by calculating the average sales per customer and applying that factor to the sales forecasts provided by the natural gas utilities. Residential accounts constitute more than 90% of the total natural gas accounts. Single-family and single-family low income customers in combination constitute around 75% of the total approximately, followed by regular and low income multifamily together at more than 15%. C&I natural gas accounts is less across all segments is less than 10%.

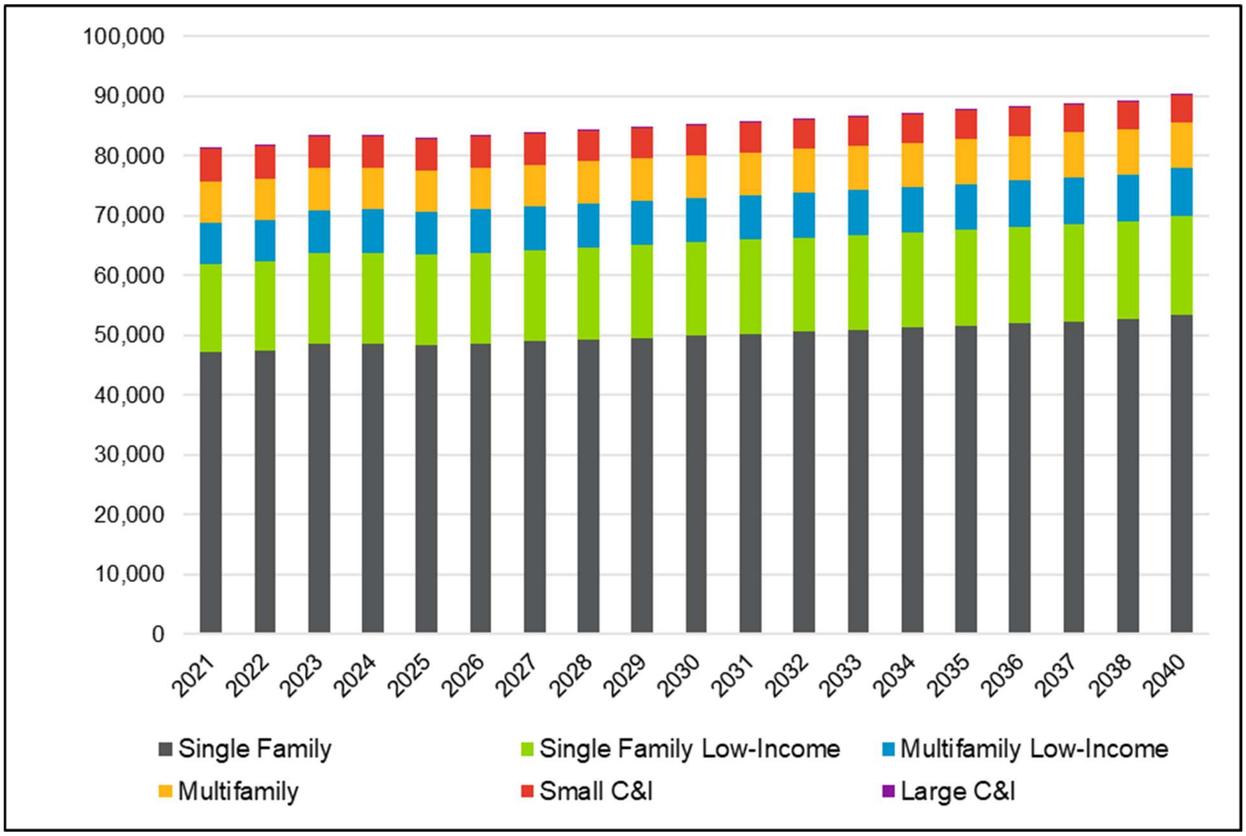
Figure 2-4. Lower Peninsula Natural Gas Account Projections by Customer Segment



Source: Guidehouse analysis

Figure 2-5 summarizes the natural gas account count projections by customer segment for the Upper Peninsula.

Figure 2-5. Upper Peninsula Natural Gas Account Projections by Customer Segment



Source: Guidehouse analysis

2.2.2 Peak Demand Projections

A key element of market characterization for the DR potential study is to develop disaggregated bottom-up peak demand projections by region, peak period, customer segment, and end use, which serves as the foundation for the DR potential estimates.

2.2.2.1 Electric Baseline Peak Demand

The peak demand projections are developed following the steps summarized in Figure 2-6 and detailed below.

Figure 2-6. Electric Baseline Peak Demand Projection Steps

Define Peak Periods

- The peaks for summer and winter were defined as the average system-wide peak demand during the top 40 hours in each season.

Develop Annual Sales Forecast

- Use data from utilities, MPSC, FERC Form 1, and EIA Form 861, develop annual gas and electric energy consumption forecasts for each customer segment.

Calculate Load Factor (LF)

- Develop load factors to convert annual sales forecasts to peak demand forecasts.

Calculate Baseline Peak Forecast

- The load factors were applied to segment-level sales forecasts to generate baseline peak forecasts for both summer and winter.

Incorporate Energy Efficiency Reductions

- Update the peak demand projections to account for the energy efficiency reductions estimated by the EWR potential study conducted by Guidehouse for MPSC.

Estimate End Use Contribution to Peak

- Guidehouse used normalized end use loadshapes, end use allocations from the EWR market characterization, and annual energy consumption to estimate the percentage of the peak attributable to each end use (HVAC, water heating, etc) during the peak period.

1. **Define Peak Periods:** The peaks for summer and winter were defined as the average system-wide peak demand during the top 40 hours in each season. Seasonal definitions were based on utility-specific DR programs with specified seasonality or on utility tariffs. The peaks and the peak hours were identified for each utility with 8,760 data.
2. **Develop Annual Sales Forecast:** Guidehouse used data from utilities, MPSC, FERC Form 1, and EIA Form 861, to develop annual natural gas and electricity consumption forecasts for each customer segment and region for the utilities included in the study. The values developed for EWR were leveraged for this step.
3. **Calculate Load Factor (LF):** To convert annual sales forecasts to peak demand values, a load factor (ratio of peak load to average load) needs to be calculated. Where 8,760 load shapes were provided, Guidehouse normalized the load shapes and calculated the load factors as an average over each of the seasonal peak periods. For utilities that did not provide load shapes, the load factor from DTE or Consumers Energy was applied.
4. **Calculate Baseline Peak Forecast:** The load factors were applied to segment-level sales forecasts to generate baseline peak forecasts for both summer and winter
5. **Incorporate Energy Waste Reductions**: Energy waste reductions were assumed to follow the same load shape as the baseline sales forecast. Per-utility load factors were then applied to the EWR potential to obtain baseline peak reductions, and the reductions were applied to the previously calculated baseline peak.

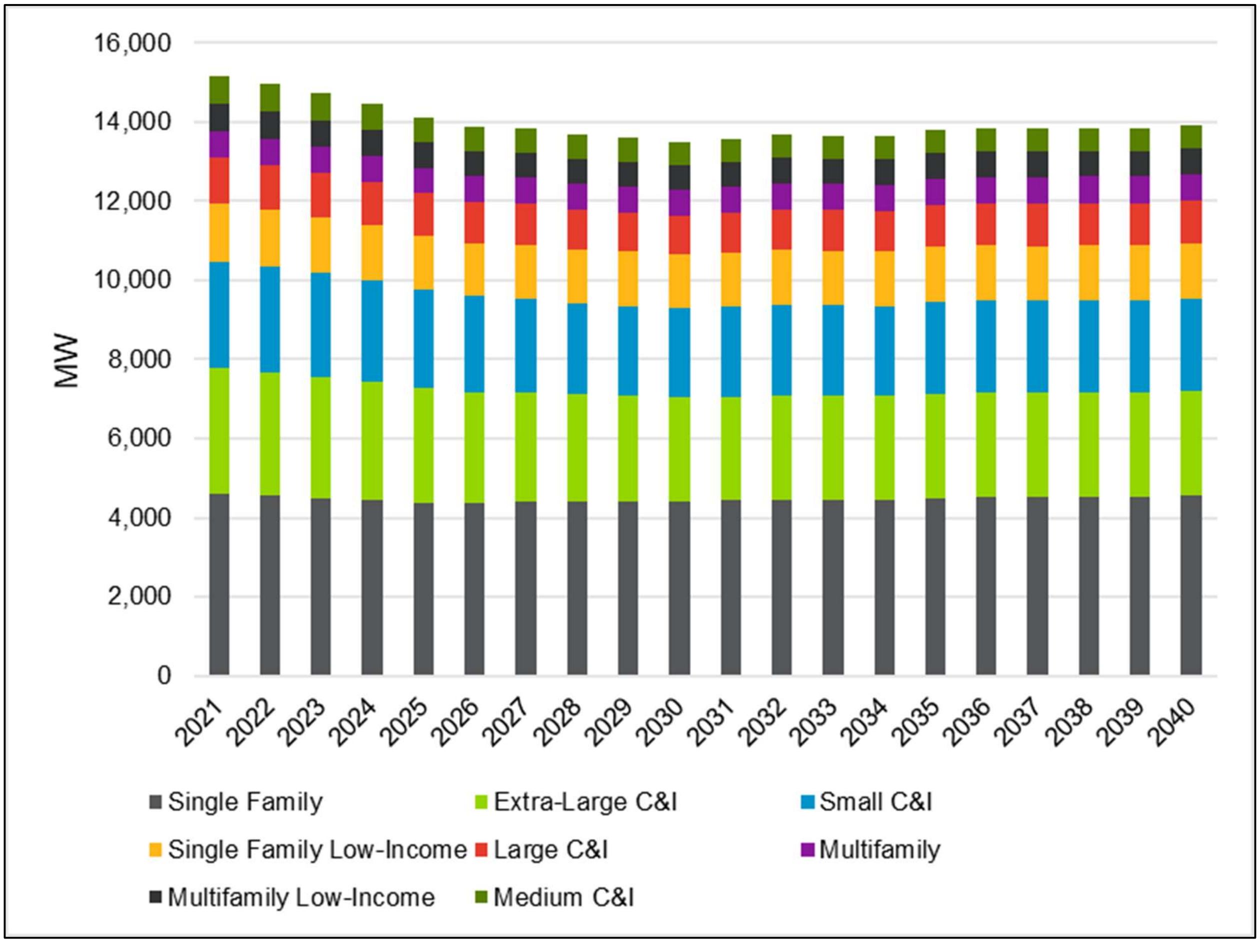
6. **Estimate End Use Contribution to Peak:** For DR options where the unit impacts are characterized as "% reduction in end use load", the end use contribution to the peak load is required for assessing DR potential. This approach only applies to certain DR options for C&I customers. In order to derive the end use shares in peak demand, Guidehouse first identified the peak period for end use load shapes by using the top 40 hours for each season of the Other load shape.[7] The primary data source for the load shapes was DTE's 2015 End Use C&I load shapes for DSMore[8]. The normalized load shapes for each end use were averaged over the peak period to obtain a peak factor, which was then applied to annual end use consumption of the base year (2019) to obtain end-use peak in megawatts. The end-use peak values were then used to assess each end-use's percentage contribution to peak demand.

[7] Other was used because no whole building load shape was provided.

[8] Demand Side Management Option Risk Evaluator, Integral Analytics, https://iawpwebappp01.azurewebsites.net/index.php/dsmore-2/

Figure 2-7 shows the Reference Scenario baseline electric peak demand for the Lower Peninsula during summer. The decline in peak demand is due to EWR impacts on the peak demand as increased adoption of EWR measures over time leads to lowering of the peak demand. In terms of segment shares, regular single-family customers constitute a third of the peak demand followed by extra-large C&I customers with around 20% share in the peak demand. Small C&I customers have slightly lower contribution at around 17% of the total peak demand. Large C&I has approximately 8% share in total. Single-family low income has 10% share, followed by multifamily and multifamily low income each at 5% share. Medium C&I customers have less than 5% share in total peak demand. These peak demand projections do not include EVs, which is shown separately later in this section.

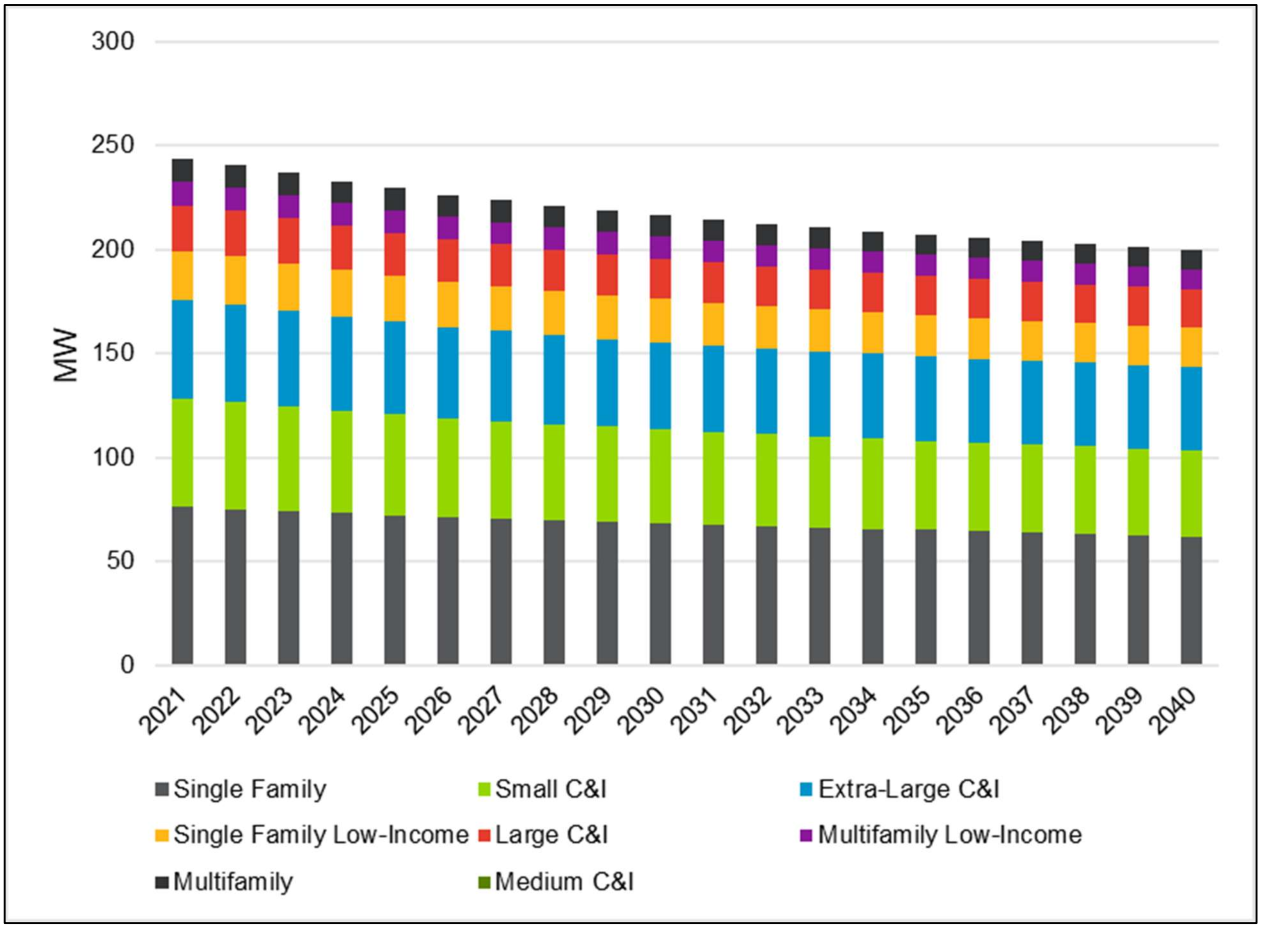
Figure 2-7. Lower Peninsula Reference Scenario Summer Baseline Electric Peak Demand Projection by Customer Segment (Net of EWR at Meter)



Source: Guidehouse analysis

Figure 2-8 shows the Reference Scenario electric baseline summer peak demand by customer segment for the Upper Peninsula. Similar to the Lower Peninsula, the declining trend in peak demand projections is due to the higher penetration of EWR measures which leads to permanent demand reduction. Regarding segment shares in the peak demand, regular single-family customers have the highest share and constitute 30% of the total peak demand, followed by the extra-large and small C&I segments, with each at 20% share in the total peak demand. Single-family low income customers constitute around 10% of the peak demand. Similarly, large C&I customers have around 10% share in total peak. Regular multifamily and multifamily low income segments each have a 5% share of the total peak demand. These peak demand projections do not include EVs, which is shown separately later in this section.

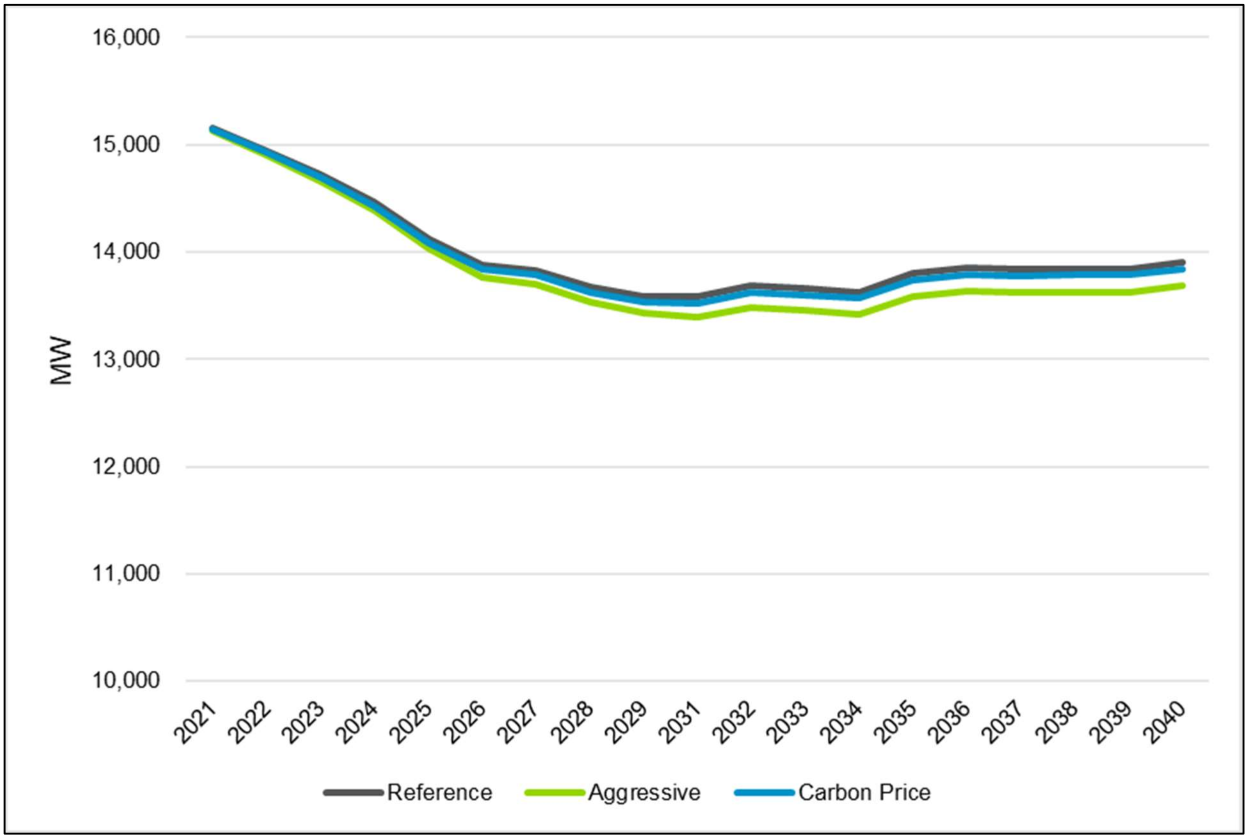
Figure 2-8. Upper Peninsula Reference Scenario Summer Baseline Electric Peak Demand Projection by Customer Segment (Net of EWR at Meter)



Source: Guidehouse analysis

Figure 2-9 shows the summer electric baseline peak demand by the three scenarios considered in the study for the Lower Peninsula. The slight differences across the scenarios are due to different EWR projections, which are incorporated as reductions to the baseline peak.[9] The y-axis has been adjusted to accentuate the differences across scenarios. These peak demand projections exclude EVs which is shown separately later in this section.

Figure 2-9. Reference Scenario Lower Peninsula Summer Baseline Electric Peak Demand Projection by Scenario (Net of EWR at Meter)

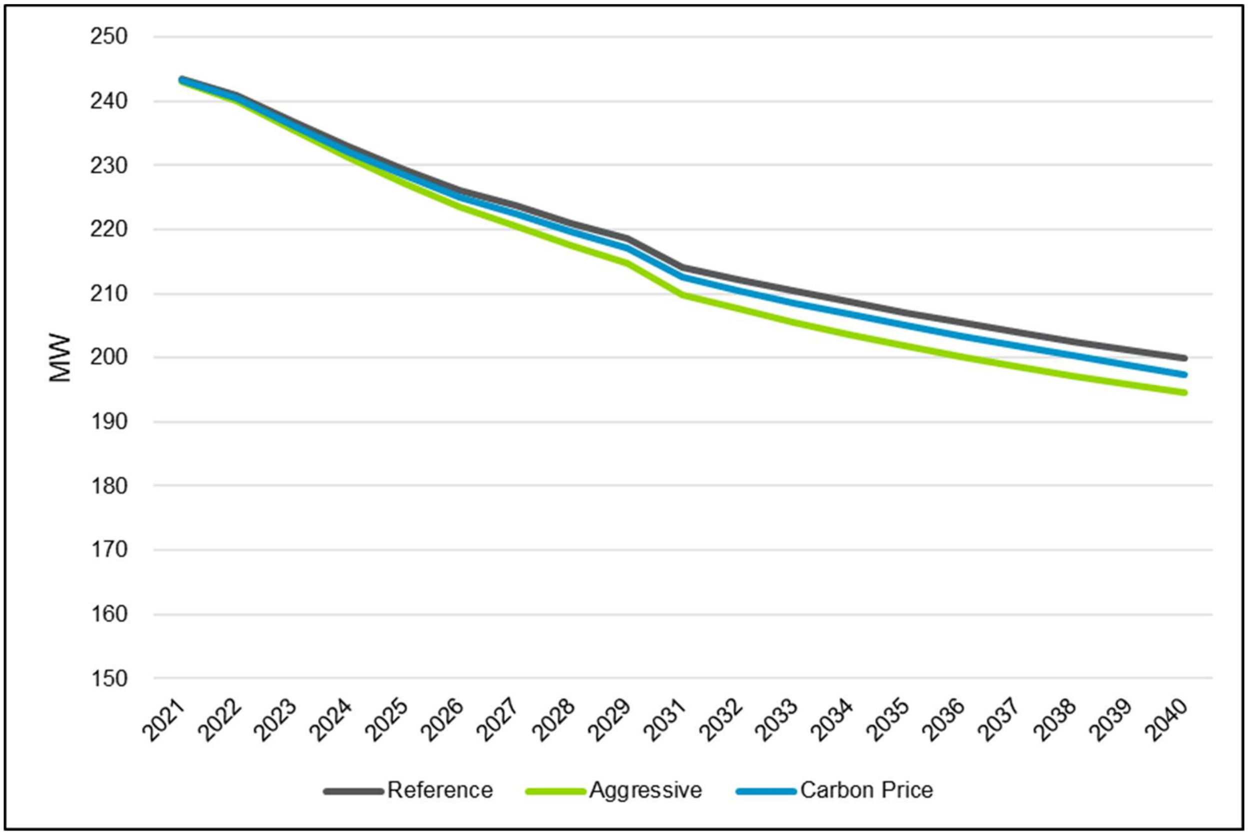


Source: Guidehouse analysis

[9] The scenarios are described later in Section 2.5.1.

Figure 2-10 shows the summer electric baseline peak demand by scenario for the Upper Peninsula during the summer peak period. These peak demand projections exclude EVs, which is shown separately later in this section.

Figure 2-10. Reference Scenario Upper Peninsula Summer Baseline Electric Peak Demand Projection by Scenario (Net of EWR at Meter)



Source: Guidehouse analysis

2.2.2.2 Natural Gas Baseline Peak Demand

The natural gas baseline peak development followed steps outlined in Figure 2-11.

Figure 2-11. Natural Gas Baseline Peak Demand Projection Steps

Define Peak Periods

- The peak is defined as the utility peak design day.

Develop Annual Sales Forecast

- Use data from utilities, FERC Form 1, and EIA Form 861, develop annual natural gas and electric energy consumption forecasts for each customer segment.

Calculate Load Factor (LF)

- To convert annual sales forecasts to peak demand values, Guidehouse calculated a load factor (ratio of peak load to average load) by using residential loadshapes from the NREL Open EI database.

Calculate Baseline Peak Forecast

- Use residential load factors, gas sales forecasts, and system peak day forecasts to determine peak day demand by customer segment.

Estimate End Use Contribution to Peak

- Update the peak demand projections to account for the energy efficiency reductions estimated by the EWR potential study conducted by Guidehouse for MPSC.

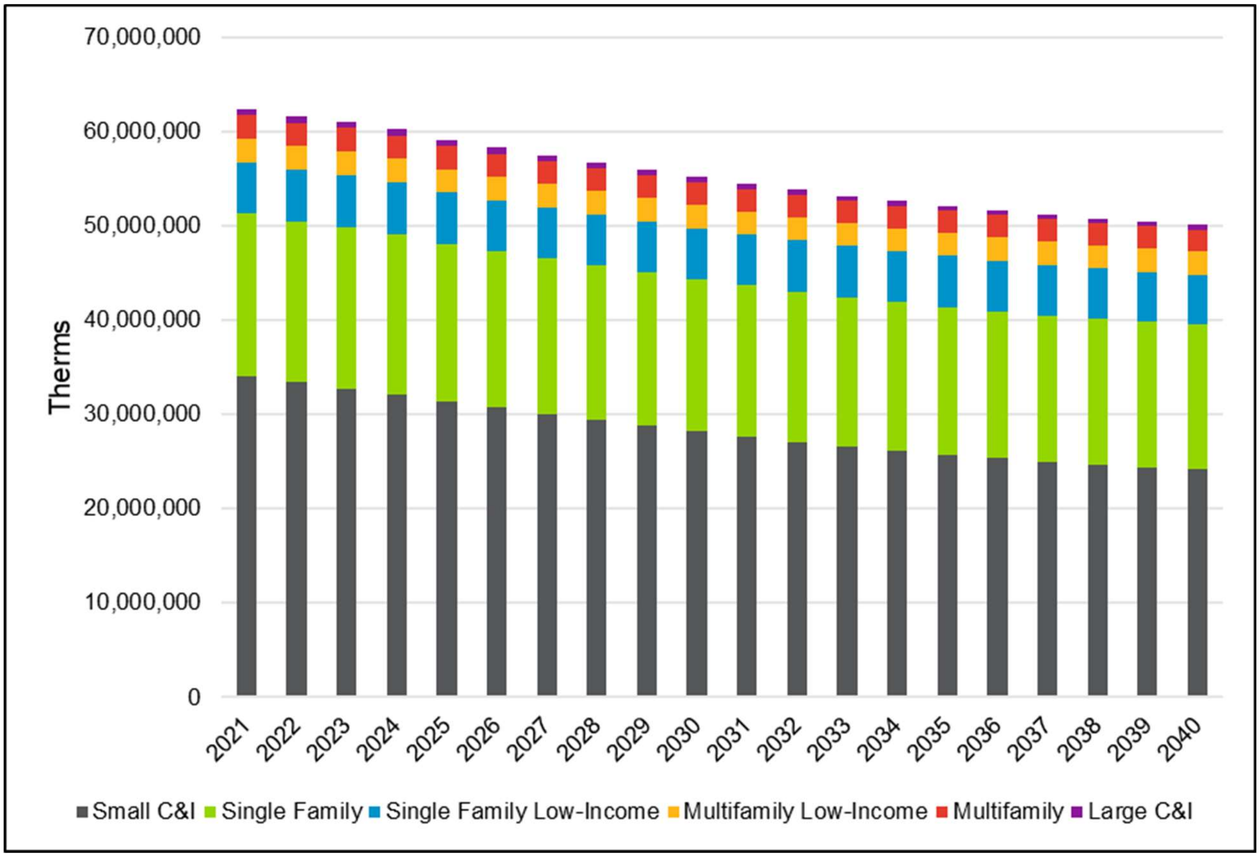
1. **Define Peak Periods**: The natural gas baseline peak forecast defines the peak as the utility peak design day. Guidehouse used this definition because no utility was able to provide hourly 8,760 natural gas consumption data, but all were able to provide peak design day consumption forecasts. These peak design days are typically expected to occur in January; thus, baseline natural gas peak projections are only developed for winter.
2. **Develop Annual Sales Forecast:** Guidehouse used data from utilities, MPSC, FERC Form 1, and EIA Form 861, develop annual natural gas and electricity consumption forecasts for each customer segment and region for the utilities included in the study. The values developed for EWR were leveraged for this step.
3. **Calculate Load Factor (LF):** To disaggregate to the residential and C&I sector level, Guidehouse used load shapes from the NREL Open EI database[10] to calculate residential peak-day natural gas load factors. The Detroit Metro and Sault Ste Marie load shapes were used to represent the Lower Peninsula and the Upper Peninsula, respectively.
4. **Calculate Baseline Peak Forecast:** These residential load factors were then applied to residential sector natural gas sales forecasts to determine peak day demand for the residential sector. C&I sector peak day demand values were then obtained by subtracting the residential peak demand from the previously calculated system-level peak day forecasts.

[10] Load shapes used were sourced from https://openei.org/datasets/files/961/pub/.

5. **Incorporate Energy Waste Reduction Savings**: The energy waste reduction savings from the EWR potential study also conducted by Guidehouse for MPSC were assumed to follow the same load shape as the baseline sales forecast. Per-utility load factors were then applied to the EWR potential to obtain baseline peak reductions, and the reductions were applied to the previously calculated baseline peak.

Figure 2-12 shows the Reference Scenario natural gas peak demand projection by customer segment for the Lower Peninsula. Similar to electric, the declining trend is a result of increased natural gas EWR in the later years. The small C&I segment and the residential segments each constitute approximately half of the total peak demand. Large C&I customers have approximately 1% share in total natural gas peak demand.

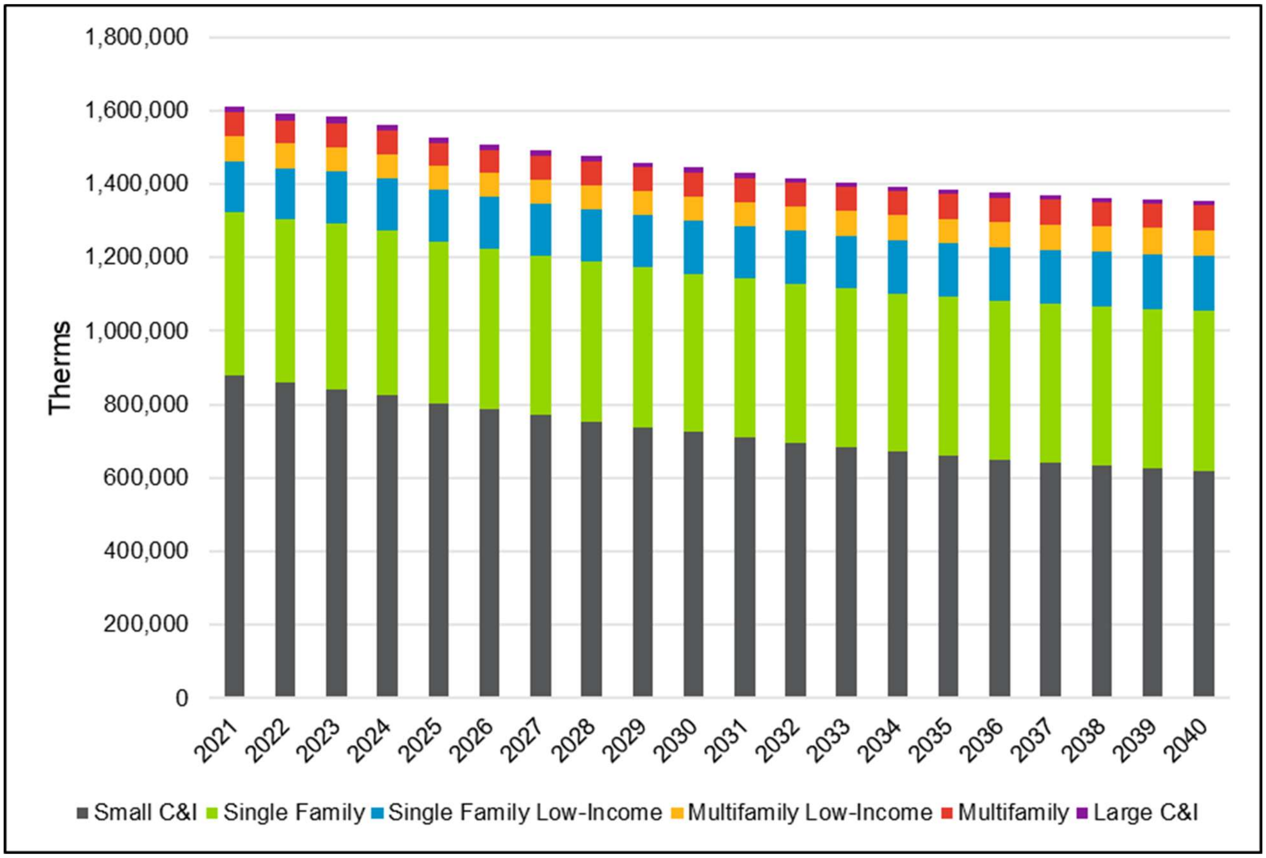
Figure 2-12. Reference Scenario Lower Peninsula Baseline Winter Natural Gas Peak Demand Projection by Customer Segment (Net of EWR at Meter)



Source: Guidehouse analysis

Figure 2-13 shows the Reference Scenario Upper Peninsula baseline natural gas peak demand in the winter peak period by customer segment. The customer segment shares in natural gas demand for the Upper Peninsula are similar to those for the Lower Peninsula.

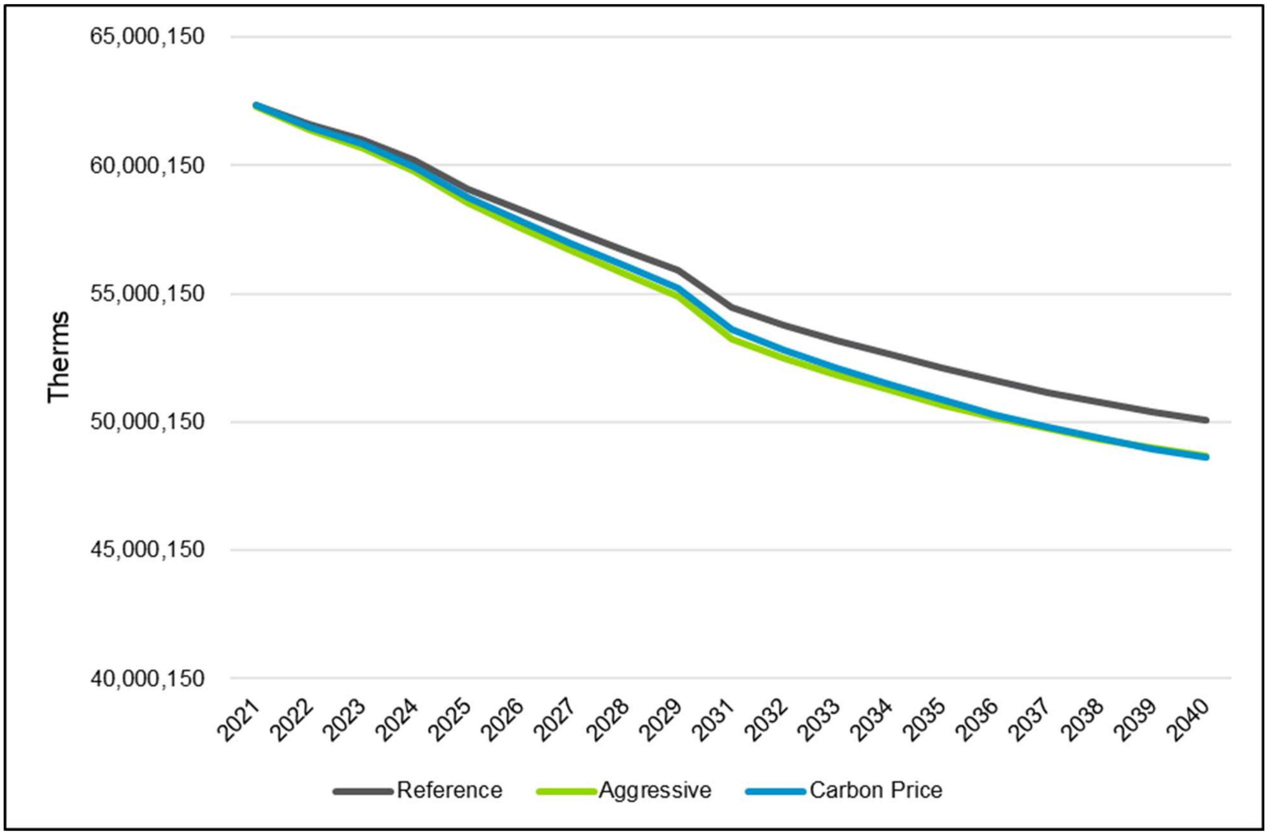
Figure 2-13. Reference Scenario Upper Peninsula Baseline Winter Natural Gas Peak Demand Projection by Customer Segment (Net of EWR at Meter)



Source: Guidehouse analysis

Figure 2-14 shows the natural gas baseline peak demand by scenario for the Lower Peninsula for the winter peak period. The slight differences across the scenarios are due to different EWR projections, which are incorporated as reductions to the baseline peak. The lower projections in the two scenarios with respect to the Reference Scenario is due to greater demand reductions from higher penetration of EWR measures. The y-axis has been adjusted to accentuate the differences across scenarios.

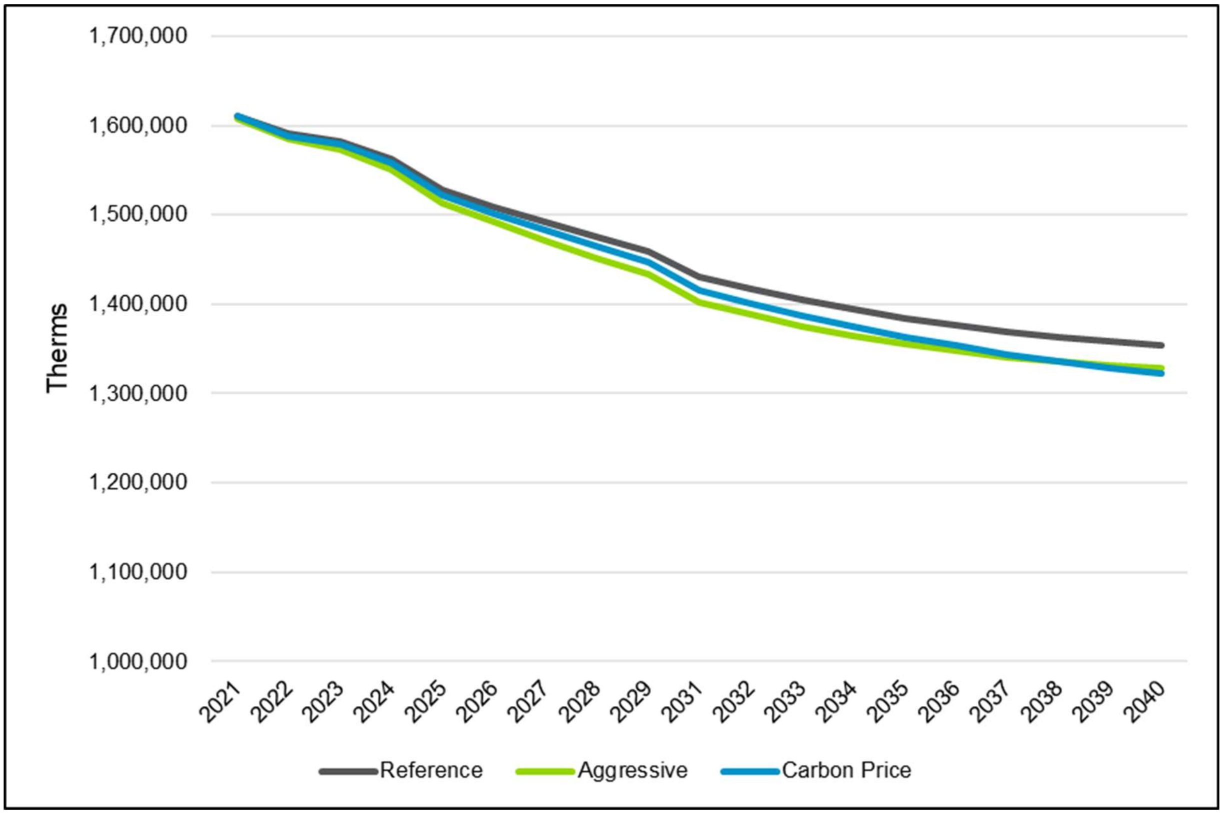
Figure 2-14. Reference Scenario Lower Peninsula Baseline Winter Natural Gas Peak Demand Projection by Scenario (Net of EWR at Meter)



Source: Guidehouse analysis

Figure 2-15 shows the natural gas baseline peak demand by scenario for the Upper Peninsula for the winter peak period.

Figure 2-15. Reference Scenario Upper Peninsula Baseline Winter Natural Gas Peak Demand Projection by Scenario (Net of EWR at Meter)



Source: Guidehouse analysis

2.2.3 Behind-the-Meter (BTM) Battery Projections

Guidehouse developed high-level battery adoption forecasts using assumptions drawn from Guidehouse Insights[11] reports and industry expertise.[12] No BTM battery projection data was available from either the MPSC or the Michigan utilities.

To forecast battery adoption by customer segment, Guidehouse first estimated the size of the battery to be 5 kW and 10% of the customer demand and the capacity to be two hours, since smaller capacities tend to be more economically feasible. Then, upfront costs and operation and maintenance (O&M) costs based on information in Guidehouse Insights reports were used to calculate equipment costs borne by the customer. Annual customer bill savings were determined by obtaining demand and energy charges from utility tariffs and calculating the demand charge savings for C&I customers and energy arbitrage values for customers with a time-varying rate. This information was used to calculate the simple payback period for each

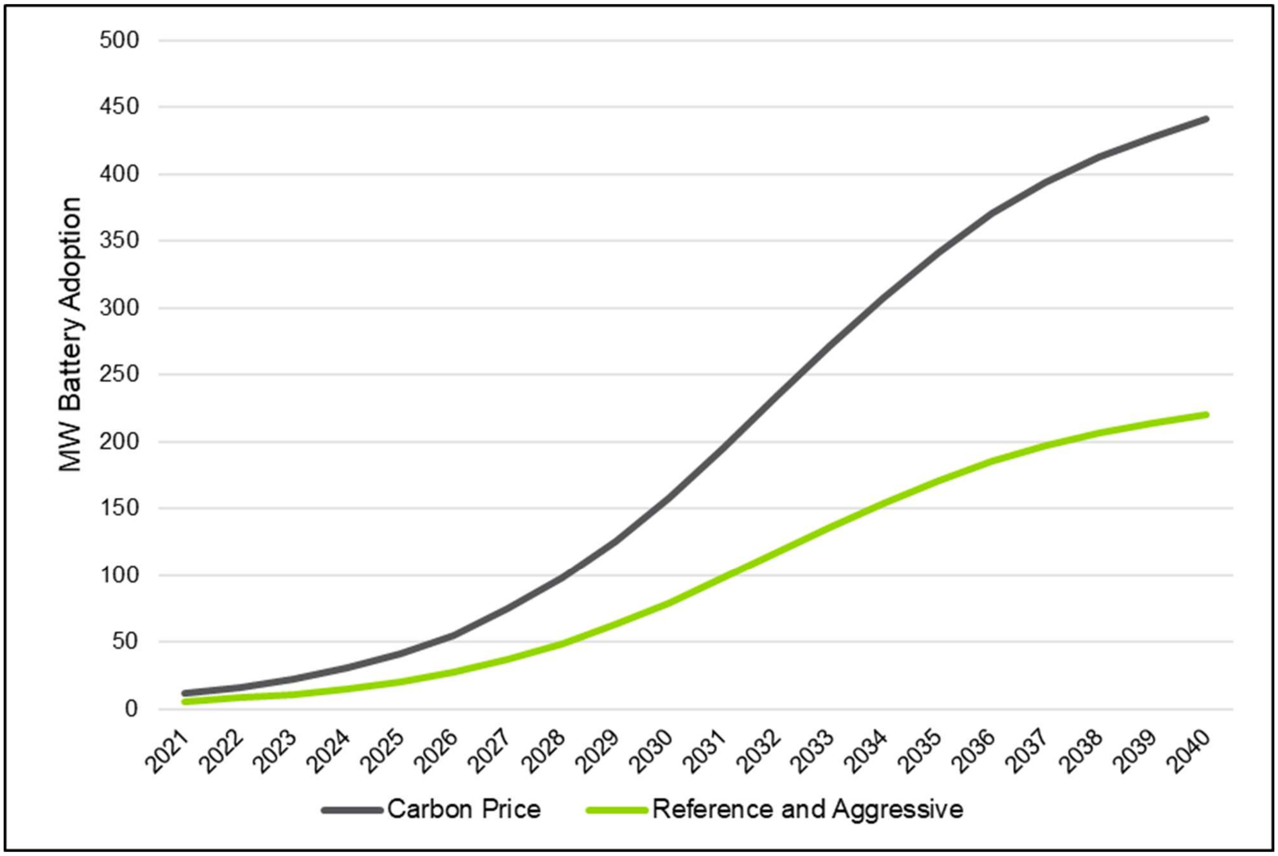
[11] https://guidehouseinsights.com/

[12] Battery projections are typically an input to the DR analysis but are not necessarily developed as part of the analysis. Due to a lack of information/data on battery projections in Michigan, Guidehouse developed high-level battery projections using an approach that estimates battery adoption based on simple payback analysis. Detailed modeling of battery projections was outside the scope of the DR study.

customer segment, which in conjunction with payback acceptance curve,[13] determines the long-run equilibrium level of customer adoption. This is a purely economic analysis, and other factors such resiliency are not accounted for in the adoption analysis. The adoption was then simulated to follow a Bass diffusion curve with a 20-year ramp rate.

Figure 2-16 and Figure 2-17 present battery capacity forecasts developed using the methodology outlined in this section. The figures show total adoption projections for all scenarios and for the Lower Peninsula and Upper Peninsula. The Aggressive Scenario battery forecasts align with the Reference Scenario forecast, while the Carbon Price Scenario projects higher battery projections assuming that stronger climate change mitigation efforts relative to the Reference Scenario will drive higher penetration of distributed energy resources (DER), including BTM batteries. The higher Carbon Price Scenario projections are based on the Advanced Cost PV + Batteries Scenario relative to the Base Case Scenario in the Storage Futures Study conducted by NREL.[14]

Figure 2-16. Battery Adoption Projections for Lower Peninsula

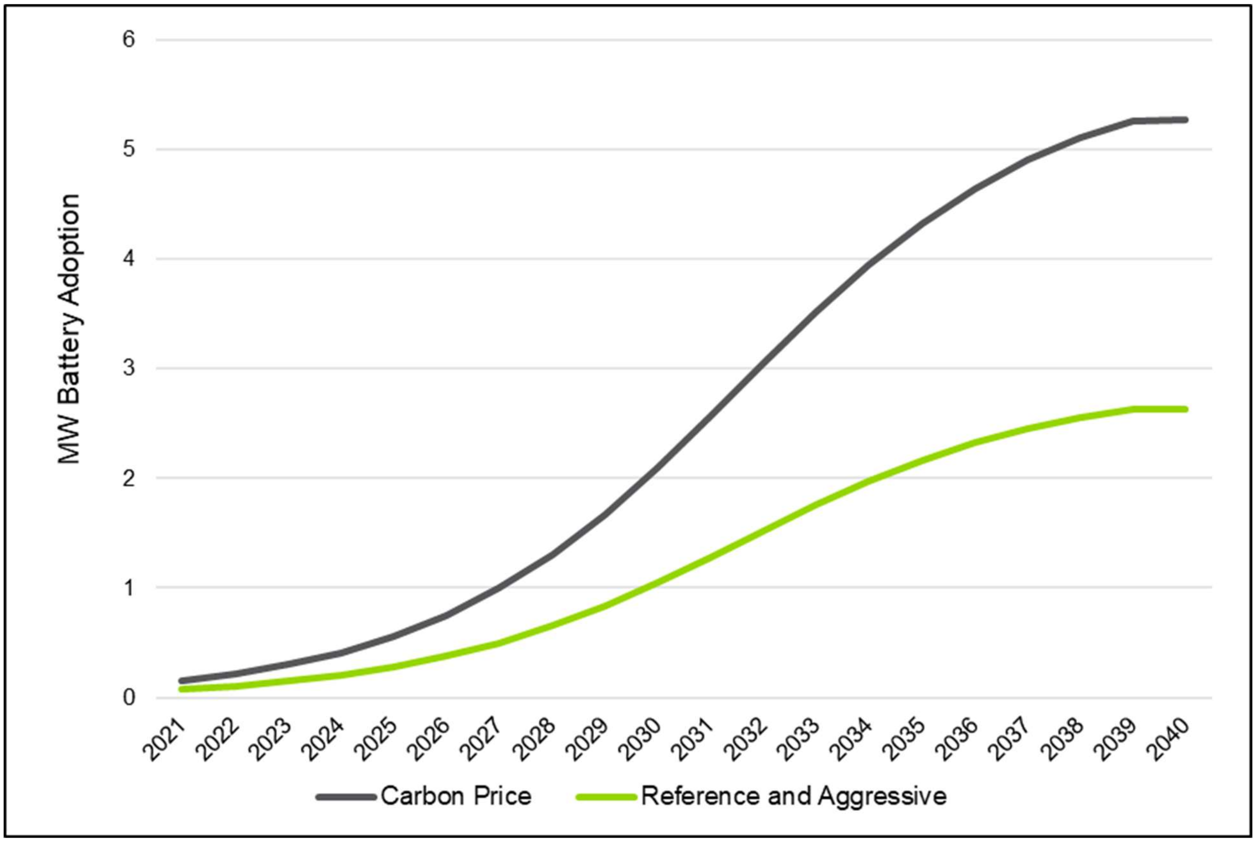


Source: Guidehouse analysis

13 Payback acceptance curves are based on Guidehouse studies on battery adoption for utilities in other jurisdictions.

14 Prasanna, Ashreeta, Kevin McCabe, Ben Sigrin, and Nate Blair. Storage Futures Study: Distributed Solar and Storage Outlook: Methodology and Scenarios. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-79790. https://www.nrel.gov/docs/fy21osti/79790.pdf.

Figure 2-17. Battery Adoption Projections for Upper Peninsula



Source: Guidehouse analysis

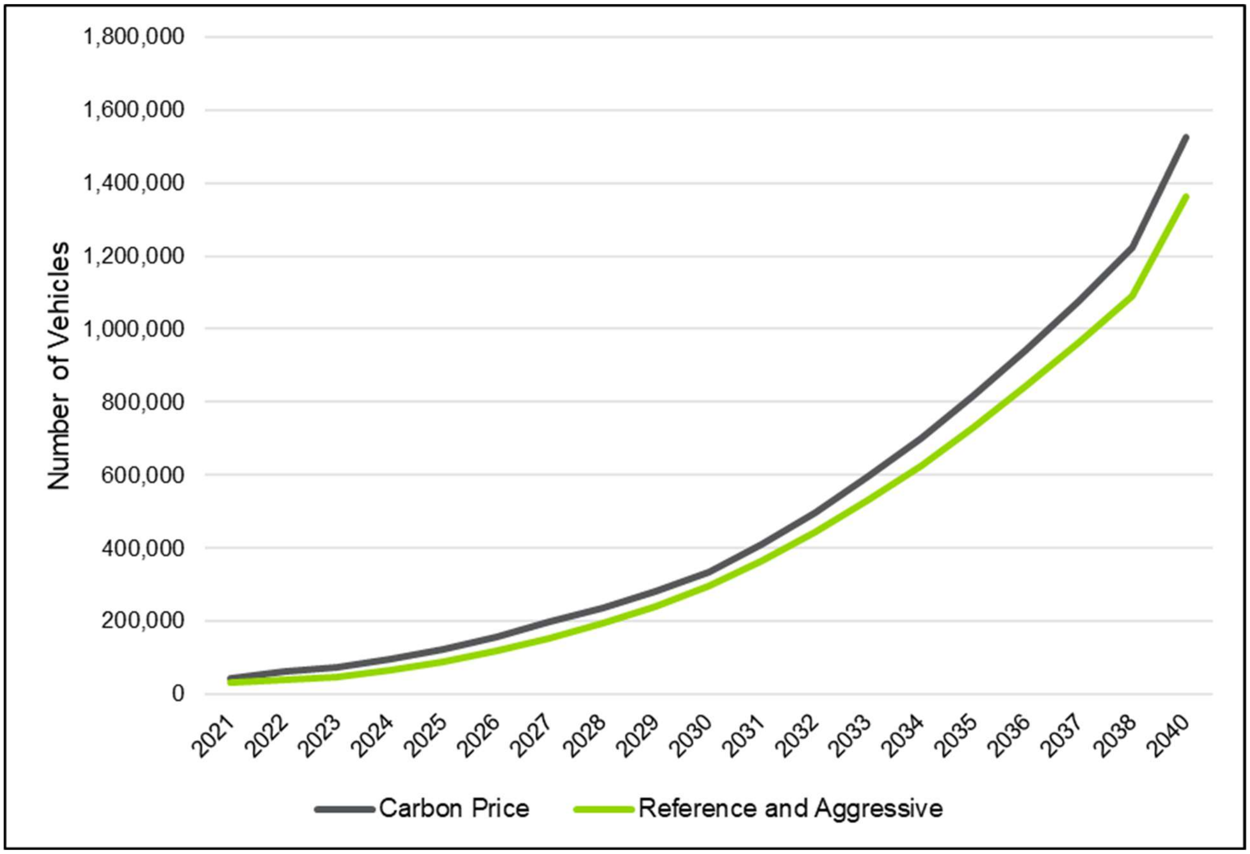
2.2.4 Electric Vehicle Projections

The electric vehicle (EV) adoption and load forecasts developed as an input to the DR model was based on Michigan EV registrations and EV projections provided by DTE and Consumers Energy. The forecasts for this study include both plug-in hybrid EVs (PHEVs) and battery EVs.

Guidehouse took the average number of EVs per household in DTE's and Consumers Energy's service territories and applied that factor to the number of households in each of the other utilities' territories to obtain the number of EVs at the utility level. Guidehouse then applied the year-over-year growth rate based on EV forecasts provided by DTE and Consumers Energy to the rest of the utilities.

Figure 2-18 and Figure 2-19 show the EV projections for the Reference Scenario and Carbon Price Scenario. The Aggressive Scenario uses the Reference Scenario forecast. The Carbon Price Scenario assumes higher penetration of EVs, driven by stronger climate change mitigation activities relative to the Reference Scenario. The higher EV projections in the Carbon Price Scenario were based on Michigan EV projections by scenario from the 2020 Q4 Guidehouse Insights EV Geographic Forecast.[15] Figure 2-18 shows the EV projections for the Lower Peninsula.

Figure 2-18. Lower Peninsula EV Adoption Forecast

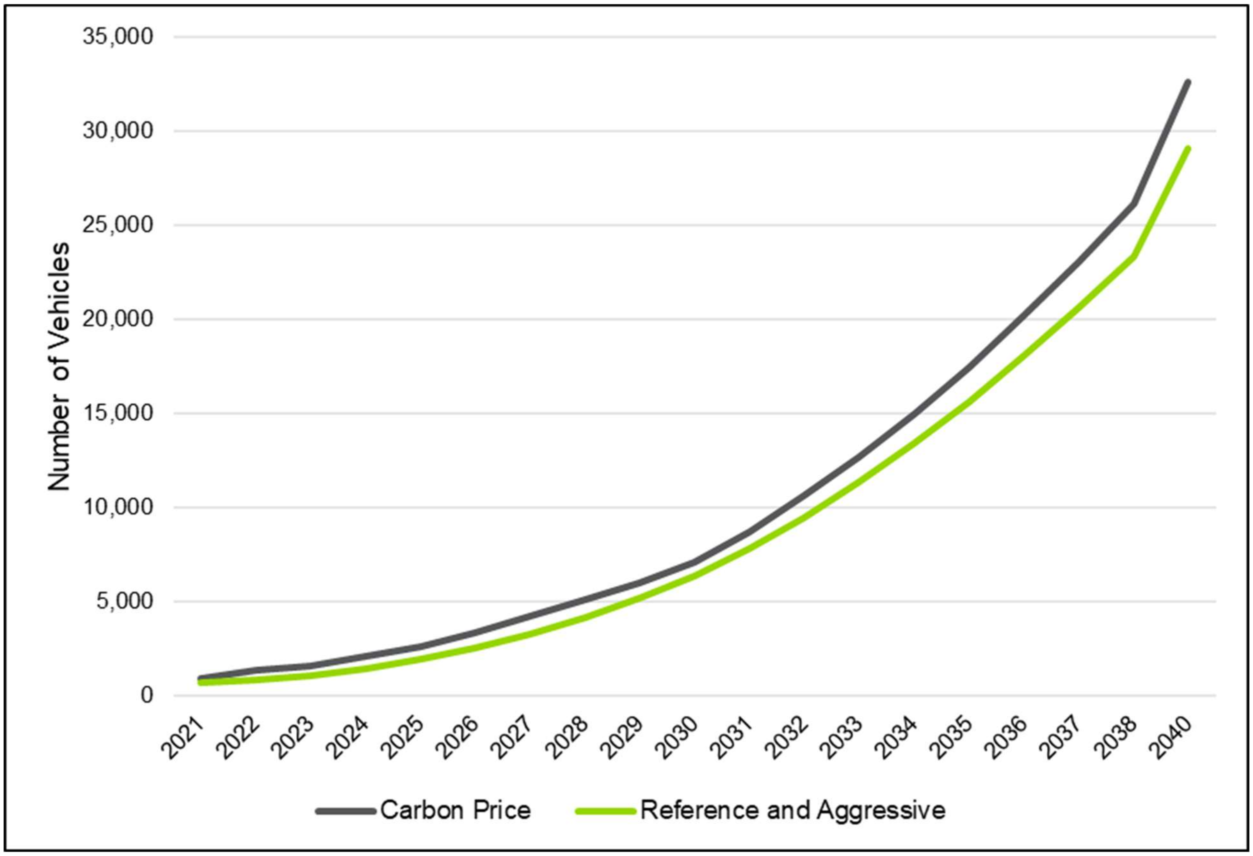


Source: Guidehouse analysis

[15] Guidehouse Insights. *Market Data: EV Geographic Forecast-North America; US and Canadian Light Duty Plug-In EV Forecasts by Province, State, and Major Metropolitan Area*. Published 4Q 2020. The higher EV projections in the Carbon Price Scenario in this analysis is based on increase in EV projections in the Aggressive scenario vis-à-vis Conservative scenario for Michigan in the Guidehouse Insights report.

Figure 2-19 shows the EV projections for the Upper Peninsula.

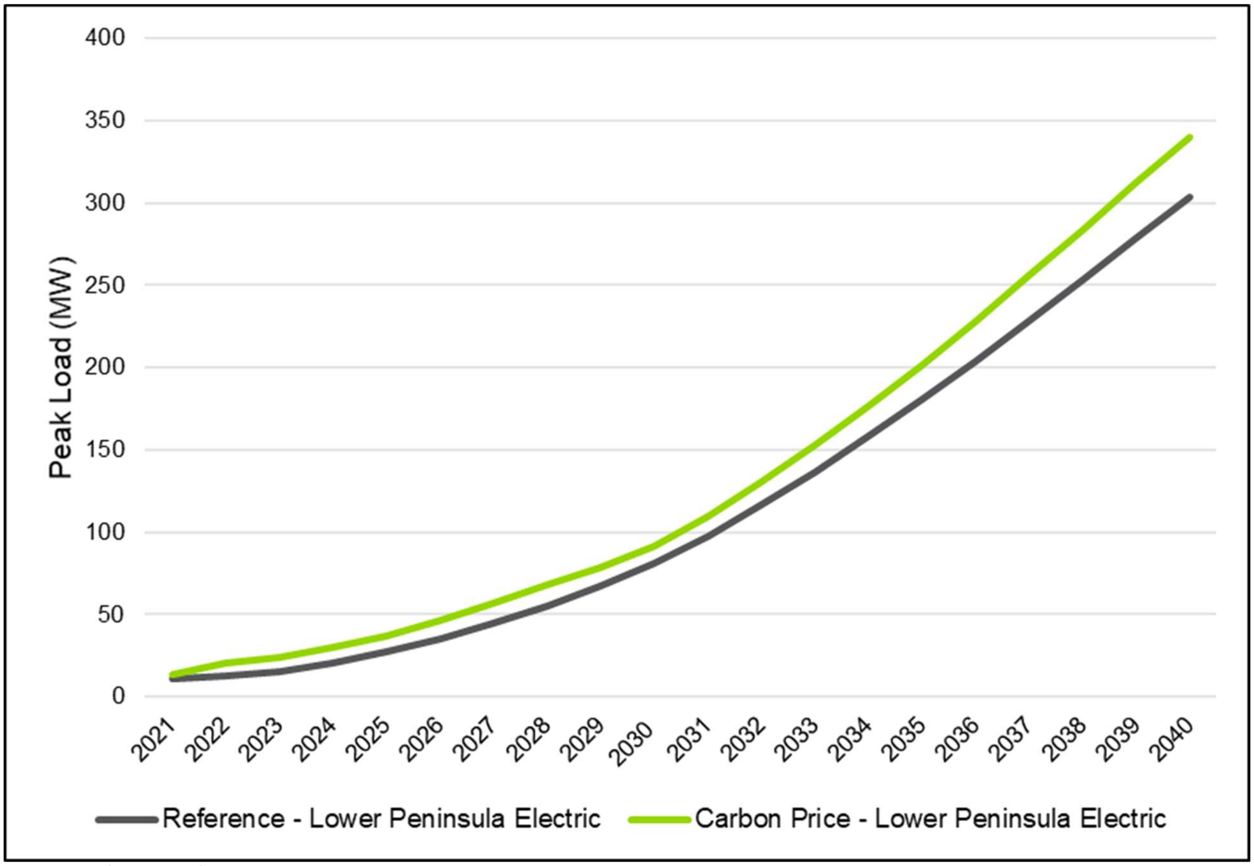
Figure 2-19. Upper Peninsula EV Adoption Forecast



Source: Guidehouse analysis

Peak demand contribution from EVs was based on 8,760 load profiles provided by Consumers Energy,[16] and the per-vehicle peak demand was calculated for each season over 3 p.m. to 6 p.m. on weekdays for each season. Figure 2-20 shows peak demand projections from EVs for the Lower Peninsula.

Figure 2-20. Lower Peninsula Peak Demand from EVs (MW at Meter)

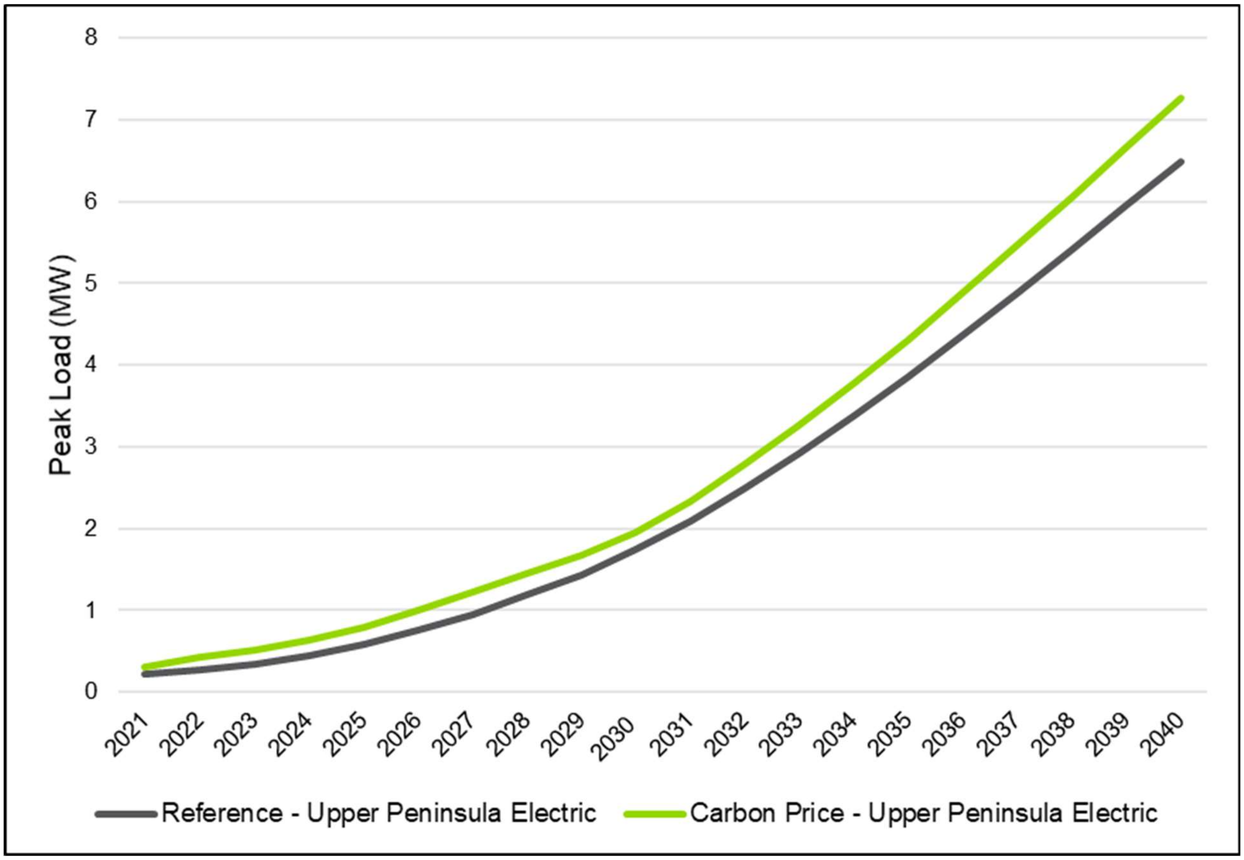


Source: Guidehouse analysis

[16] Summer period is June through September, and winter period includes all other months. The load shapes provided were for 2020.

Figure 2-21 shows peak demand contribution from EVs for the Upper Peninsula.

Figure 2-21. Upper Peninsula Charging Demand from EVs (MW at Meter)



Source: Guidehouse analysis

2.3 Descriptions of Demand Response Options and Scenarios

2.3.1 Overview of DR Options

Once the baseline peak demand projections were developed, the next key step in DR potential assessment was to characterize the different types of DR options that could be considered for realizing peak demand reductions. As stated earlier, Guidehouse considered DR options and associated enabling technologies to realize summer peak reduction plus winter peak reduction for electricity, and additionally separate DR options to realize winter peak reduction for natural gas.

Table 2-2 summarizes the DR options included in the analysis. The DR options represent the DR programs and rates that Michigan utilities currently offer and could potentially offer based on existing and emerging DR programs and enabling technology offers in the industry. Table 2-3 shows how the DR options are mapped to different DR suboptions. These suboptions represent combinations of different end-uses and enabling technologies that can help realize demand reductions during DR events.

Electric DR options considered for residential customers (all residential segments) included the following (described in Table 2-2 and Table 2-3):

- Incentive-based DR options such as:
  - Direct load control (DLC) using switches and smart thermostats to control space cooling and/or heating and water heating. This included both direct install (DI) and bring your own thermostat (BYOT) implementation approaches.
  - Smart appliances control using a bring your own device (BYOD) implementation approach
  - EV Managed Charging
  - BTM battery dispatch
- Pricing options such as:
  - Time-of-use (TOU) rates
  - Critical peak pricing (CPP)
  - Peak time rebate (PTR)
- Behavioral DR

Electric DR options considered for C&I customers included the following (described below in Table 2-2 and Table 2-3):

- Incentive-based DR options such as:
  - DLC using switches and smart thermostats to control space cooling and/or heating and water heating (only applies to small and medium C&I customers)
  - C&I capacity reduction (applies to large and extra-large C&I customers)
  - Demand bidding (applies to large and extra-large C&I customers)
  - EV managed charging (applies to all C&I segments)
  - BTM battery dispatch (applies to all C&I segments)
  - Thermal energy storage (TES) for load reduction during DR events (applies to large and extra-large C&I customers)
- Pricing options such as:
  - TOU rates
  - CPP
  - PTR

In addition to the electric DR options listed previously, Guidehouse included voltage optimization as a DR option that considers conservation voltage reduction (CVR) methods to achieve demand reductions.[17]

Natural gas DR options considered for residential customers (all residential segments) included the following (described in Table 2-2 and Table 2-3):

[17] Voltage optimization is typically not considered as a DR Option. However, MPSC indicated that stakeholders were interested in including this under the DR analysis and therefore Guidehouse included this as a DR Option in this study.

- Incentive-based DR options such as:
  - DLC using smart thermostats and switches to control space heating and water heating.
- Behavioral DR

Natural gas DR options considered for C&I customers included the following (described below in Table 2-2 and Table 2-3):

- Incentive-based DR options such as
  - DLC using smart thermostats and switches to control space heating and water heating. This only applies to small C&I customers.
  - C&I capacity reduction (applies to large C&I customers)

Table 2-2. Descriptions of DR Options

DR Options	Brief Description	Eligible Customers
Electric DR Options		
DLC-Switch for Space Cooling and Heating, Water Heating	Control of space cooling and heating equipment (central AC, heat pumps, electric furnaces), and electric water heating using load control switches.	All residential, small C&I, and medium C&I customers with eligible end uses.
DLC-Smart Thermostat BYOT	BYOT program with space cooling and heating control using smart thermostats.	All residential, small, and medium C&I customers with smart thermostats.
Smart Appliances Control (including Room AC)	Remote control of Wi-Fi-enabled smart appliances; appliances may also be controlled using a smart plug.	Residential customers with smart appliances.
Behavioral DR	Modifications in demand during peak demand period due to behavioral changes, induced by social comparisons.	All residential customers
Capacity Reduction	Firm capacity commitment for load reduction during DR events; customers receive both a fixed capacity payment ($/kW) based on committed load reduction, plus an energy payment ($/kWh). Curtailment can be either manual or automated.	Large C&I, extra-large C&I customers.
Demand Bidding	Voluntary load reduction when DR events are called. There is no capacity commitment. Customers voluntary reduce load and receive energy payment ($/kWh) only based on. Curtailment can be either manual or automated.	Large C&I, extra-large C&I customers.

DR Options	Brief Description	Eligible Customers
Time-of-Use (TOU) Rates	Rates that vary by block of hours during the day and by season.	Residential, all C&I customers.
Critical Peak Pricing (CPP)	Significantly higher price during certain critical hours of the year (high demand), superimposed on a TOU rate; off-peak rate is lower than otherwise applicable tariff.	Residential, all C&I customers.
Peak Time Rebate (PTR)	Discounted rate for reducing electricity use over baseline during DR events.	Residential, small C&I customers.
Real Time Pricing (RTP)	Dynamic rate with hourly variation in price.	Large C&I, extra-large C&I customers.
EV Load Control	Managed charging of PHEVs and EVs.	Customers with PHEVs and EVs.
Behind-the-Meter (BTM) Battery	Dispatch of BTM batteries during DR events.	Customers with BTM batteries.
Thermal Energy Storage (TES)	Load shifting to TES systems (either ice storage or phase change materials) during DR events.	All C&I customers with TES systems.
Voltage Optimization (VO)	Energy and demand reduction using front-of-the-meter VO technologies.	All customers.
Natural Gas DR Options		
DLC-Smart Thermostat BYOT	Bring your own thermostat (BYOT) program with space cooling and heating control using smart thermostats.	All residential and small C&I customers with smart thermostats for gas space heating control.
DLC-Switch for Water Heating	Control of gas water heating using load control switches.	All residential and small C&I, customers with gas water heating
Behavioral DR	Modifications in demand during peak demand period due to behavioral changes, induced by social comparisons.	All residential customers.
Capacity Reduction	Firm capacity commitment for load reduction during DR events; customers nominate a certain reduction amount, similar to electric and get paid based on their nomination and actual energy reduced during DR events.	Large C&I customers.

Source: Guidehouse

Table 2-3. Mapping of DR Suboptions to DR Options

DR Option	DR Suboption
Electric	
Direct Load Control (DLC) - Switch	DLC-Switch-Space Cooling
	DLC-Switch-Space Heating
	DLC-Switch Water Heating
DLC - Smart Devices	Bring Your Owen Thermostat (BYOT)-Space Cooling
	Bring Your Own Thermostat (BYOT)-Space Heating
	DLC-Smart Thermostat-Space Cooling
	DLC-Smart Thermostat-Space Heating
	Bring Your Own Device (BYOD)-Smart Room AC
	Bring Your Own Device (BYOD)-Ductless Mini Splits
	Bring Your Own Device (BYOD)-Smart Water Heater
	Bring Your Own Device (BYOD)-Smart Pool Pump
	Bring Your Own Device (BYOD)-Smart Clothes Washer
	Bring Your Own Device (BYOD)-Smart Clothes Dryer
C&I Capacity Reduction	C&I Capacity Reduction- Manual HVAC Control
	C&I Capacity Reduction- Auto-DR HVAC Control
	C&I Capacity Reduction- Water Heating
	C&I Capacity Reduction- Standard Lighting Control
	C&I Capacity Reduction- Advanced Lighting Control
	C&I Capacity Reduction- Others
	C&I Capacity Reduction-Total Facility
C&I Demand Bidding	C&I Demand Bidding- Manual HVAC Control
	C&I Demand Bidding- Auto-DR HVAC Control
	C&I Demand Bidding- Water Heating
	C&I Demand Bidding- Standard Lighting Control
	C&I Demand Bidding- Advanced Lighting Control
	C&I Demand Bidding- Others
	C&I Demand Bidding-Total Facility
Time of Use (TOU)	Time-Of-Use (TOU) Rates
Critical Peak Pricing (CPP)	Critical Peak Pricing with Enabling Tech
	Critical Peak Pricing without Enabling Tech
Peak Time Rebate (PTR)	Peak Time Rebate with Enabling Tech
	Peak Time Rebate without Enabling Tech
Real Time Pricing (RTP)	Real Time Pricing with Enabling Tech
	Real Time Pricing without Enabling Tech
Electric Vehicle (EV) Managed Charging	Electric Vehicle Managed Charging
Behind-the-Meter (BTM) Battery Dispatch	Behind-the-Meter (BTM) Battery Dispatch

DR Option	DR Suboption
Thermal Energy Storage (TES)	Thermal Energy Storage (TES) - Ice Storage
	Thermal Energy Storage (TES) -Phase Change Materials
Behavioral DR	Behavioral DR
Voltage Optimization (VO)	Voltage Optimization
Natural Gas	
DLC - Gas	Bring Your Own Thermostat (BYOT)-Space Heating - Gas
	DLC-Smart Thermostat-Space Heating - Gas
	DLC-Switch Water heating - Gas
	Bring Your Own Device (BYOD)-Smart Water Heater - Gas
Industrial Process Load Control - Gas	Industrial Process Load Control - Gas
Wastewater Treatment Scheduling - Gas	Wastewater Treatment Scheduling - Gas

Source: Guidehouse

2.3.2 Scenario Descriptions

Guidehouse developed potential and cost estimates for three scenarios. These are referred to as Reference, Aggressive, and Carbon Price Scenarios. These scenarios represent different input parameters for participation, incentive levels, DER adoption, avoided costs, and EWR-related adjustments. Table 2-4 summarizes the key assumptions across these three scenarios. The Aggressive Scenario models higher participation and incentive levels, and the Carbon Price Scenario models higher energy avoided cost and increased DER adoption.

Table 2-4. Summary of Scenario Descriptions

Scenario	Incentives	Participation	Energy Avoided Costs	Electric Vehicle Adoption	BTM Battery Adoption	EWR Scenario[18]
Reference	Based on existing incentives or best estimates from similar jurisdictions	Expected achievable participation[19]	Weighted average of avoided costs provided by Michigan utilities[20]	Expected adoption based on data provided by Michigan utilities[21]	Expected adoption based on customer tariffs and simple payback calculation[22]	Reference

[18] The EWR Statewide Potential study outputs inform adjustments to the baseline peak and the saturation of DR-eligible measures.

[19] For additional discussion, see Section 2.5.2.

[20] For additional discussion, see Section 2.5.4.

[21] For additional discussion, see Section 2.2.4.

[22] For additional discussion, see Section 2.2.3.

Scenario	Incentives	Participation	Energy Avoided Costs	Electric Vehicle Adoption	BTM Battery Adoption	EWR Scenario[18]
Aggressive	Higher participation relative to Reference based on survey results	Higher participation relative to Reference based on survey results	Unchanged from Reference	Unchanged from Reference	Unchanged from Reference	Aggressive
Carbon Price	Unchanged from Reference	Unchanged from Reference	Increased electricity ($/kWh) avoided costs by 50% in 2021, escalating with a 2.5% multiplier growth until a 100% increase was met[23]	Enhanced adoption based on Guidehouse Insights' EV Geographic Forecast[21]	Enhanced adoption based on Storage Futures Study conducted by NREL[22]	Carbon Price

Source: Guidehouse

The key variables for potential and cost assumptions and for benefit-cost assessment are further discussed in Section 2.5. The customer surveys helped inform the participation assumptions in the study and therefore we describe the survey approach and results first before describing how the survey results were used to develop participation assumptions.

2.4 Primary Data Collection

Guidehouse conducted online surveys of Michigan's electric and natural gas utility end-use customers to collect primary data that supplemented secondary sources to develop market acceptance and adoption forecasts. Through the primary data collection process, Guidehouse emphasized the collection of Michigan-specific data to improve the quality of the potential modelling and was not already available through recent studies.

As discussed in the following sections, the primary data collection included two online surveys: a residential survey, and a C&I survey. Each survey was used to collect data to inform DR participation projections.[24]

2.4.1 Approach to Customer Primary Data Collection

The surveys' primary objective was to collect information on customer awareness of and willingness to pay for EWR measures, and awareness and willingness to participate in DR programs. Guidehouse also included a limited number of measure baseline and saturation questions to supplement data from other studies and further inform the potential study.

[23] For additional details, refer to Section 8 of the EWR report.

[24] The surveys included both EWR and DR topics and informed inputs for both EWR and DR potential models.

In addition to awareness and willingness, Guidehouse collected customer feedback in the surveys to support achievable potential model calibration related to:

- Impacts of the COVID-19 pandemic on customer decision-making around DR programs.
- Motivating factors driving customer decision making about energy-consuming equipment in their home or business.
- Major barriers to customers taking action on the ways they consume energy in their home or business, including participation in DR programs.

All survey respondents were recruited through email solicitations and sourced from utility tracking data. Customers were offered an incentive to encourage participation through Tango, which allows customers to select an e-gift card from a participating retailer or restaurant (including Amazon.com, CVS or Dunkin' Donuts and more), or an online debit card (Visa or MasterCard), as Table 2-5 shows.

Table 2-5. Customer Incentive Details

Survey/Customer Type	Customer Incentive
Residential	$15
C&I	$25

Source: Guidehouse analysis

2.4.2 Residential Survey Response Summary

Residential customer responses were tabulated by region (Lower Peninsula and Upper Peninsula), customer income level (low income and non-low income) and residence type (single-family and multifamily). Table 2-6 shows the stratification for residential customers and the number of completed surveys in each stratum.

Table 2-6. Stratification of Residential Customer Surveys

Segment (Region-Dwelling Type-Income Level)	Completed Surveys
Lower-Multifamily-Low Income	36
Lower-Multifamily-Non-Low Income	34
Lower-Multifamily-Unknown	11
Lower-Single-Family-Low Income	48
Lower-Single-Family-Non-Low Income	170
Lower-Single-Family-Unknown	70
Lower-Unknown-Unknown	1
Upper-Multifamily-Low Income	13
Upper-Multifamily-Non-Low Income	5
Upper-Multifamily-Unknown	2

Segment (Region-Dwelling Type-Income Level)	Completed Surveys
Upper-Single-Family-Low Income	64
Upper-Single-Family-Non-Low Income	99
Total Residential Surveys	**591**

Source: Guidehouse analysis

2.4.3 C&I Survey Response Summary

Commercial and industrial customer responses were tabulated by region (Lower Peninsula and Upper Peninsula), and customer size[25] (small and large), and business type[26] (commercial or industrial). Table 2-7 shows the stratification for C&I customers and the number of completed surveys in each stratum.

Table 2-7. Stratification of Completed C&I Customer Surveys

Segment (Region-Customer Size-Business Type)	Completed Surveys
Lower-Large-Commercial	45
Lower-Large-Industrial	9
Lower-Large-Unknown	2
Lower-Small-Commercial	261
Lower-Small-Industrial	32
Lower-Small-Unknown	49
Upper-Large-Commercial	5
Upper-Large-Unknown	1
Upper-Small-Commercial	51
Upper-Small-Industrial	3
Upper-Small-Unknown	12
Total C&I Surveys	**470**

Source: Guidehouse analysis

To maximize online survey responses from large C&I customers and in the absence of a utility data flag to sample around customer size, Guidehouse implemented a small C&I customer quota of 400 in the online survey. This means that after receiving 400 small C&I completes, the survey remained open only for large customers. Upon closing the survey, Guidehouse received 408 small C&I completes and 62 large C&I completes.

[25] Large customers are defined as those customers who indicated their combined natural gas and electricity bills were more than $65,000 per year. Small customers are defined as those customers who indicated their combined natural gas and electricity bills were less than $65,000 per year.

[26] Customer business type was determined based on customer responses to a survey question.

2.4.4 Survey Methodology and Results

This section details the methodology for the primary research objectives of the survey for which responses were used as direct model inputs and brief discussion of results.

2.4.4.1 DR Awareness

Respondents were asked about a variety of common and emerging DR program types to assess awareness. Two types of questions to assess customer awareness of DR programs: one to assess awareness of DR programs currently offered by the customer's utility, and one to assess awareness of DR program types not currently offered by the customer's utility. If a respondent's utility offers a specific DR program type, they were asked about their utility's specific DR program details, all other respondents were asked about awareness of the program type in general. Table 2-8 details the DR program types asked in the surveys and differentiates between small and large C&I customers who are eligible for different DR program types.

Table 2-8. DR Program Types Included in Customer Surveys

DR Program Type	Residential	Small C&I	Large C&I
Bring Your Own Thermostat (BYOT)[27]	✓	✓	-
Capacity Reduction	-	-	✓
Demand Bidding	-	-	✓
Critical Peak Pricing (CPP)	✓	✓	✓
Critical Peak Pricing with Free Smart Thermostat	✓	✓	-
Peak Time Rebate (PTR)	✓	✓	-
Electric Vehicle (EV) Load Control	✓	-	-
Behind-the-Meter Battery Load Control	✓	✓	✓

Source: Guidehouse analysis

Results from these questions were to develop participation and program ramp-up assumptions for the DR potential model, which is further discussed in Section 2.5.2.

[27] Considered both situations – one, in which customers own a smart thermostat and enroll in a DR program; two, in which customers are provided EWR rebates to purchase a smart thermostat and enroll in a DR program.

Table 2-9 and Table 2-10 summarize DR awareness results from the residential and C&I surveys.

Table 2-9. Residential DR Awareness

DR Program Type[28]	n	% Aware & Participates	% Aware & Does Not Participate	% Aware
DTE - BYOT (Smart Savers Program)	281	7%	32%	n/a
DTE - Dynamic Peak Pricing	281	5%	31%	n/a
DTE - Smart Currents Program	281	3%	32%	n/a
DTE - Smart Charger Support	281	1%	25%	n/a
Consumers Energy - BYOT (Peak Power Savers Smart Thermostat Program)	172	12%	37%	n/a
Consumers Energy - Peak Power Savers CPP	172	13%	33%	n/a
Consumers Energy - Peak Power Savers PTR	172	16%	33%	n/a
General - BYOT	138	n/a	n/a	14%
General - CPP	138	n/a	n/a	32%
General - PTR	419	n/a	n/a	27%
General - EV Load Control	310	n/a	n/a	13%
General - Battery Control	591	n/a	n/a	10%

Source: Guidehouse analysis

Table 2-10. C&I DR Awareness

DR Program Type[29]	n	% Aware & Participates	% Aware & Does Not Participate	% Aware
DTE - BYOT (Smart Savers Program)	162	6%	31%	n/a
DTE - Dynamic Peak Pricing Program	162	5%	30%	n/a
Consumers Energy - C&I DR program (capacity plus energy payment)	33	6%	12%	n/a
Consumers Energy - C&I DR program (energy payment only)	33	15%	46%	n/a
General - BYOT	246	n/a	n/a	30%
General - CPP (Small Customers)	246	n/a	n/a	42%
General - CPP (Large Customers)	62	n/a	n/a	42%
General - Capacity Reduction	29	n/a	n/a	24%
General - Demand Bidding	29	n/a	n/a	31%
General - Battery Control	470	n/a	n/a	15%

Source: Guidehouse analysis

[28] Respondents whose utility offers an included DR program type were asked about their utility's specific DR program details and indicated whether they already participate. All other respondents were asked about awareness of the program type in general.

[29] Respondents whose utility offers an included DR program type were asked about their utility's specific DR program details and indicated whether they already participate. All other respondents were asked about awareness of the program type in general.

2.4.4.2 DR Willingness to Participate

Respondents were asked a series of questions to assess willingness to participate in the DR program types listed in Table 2-8. DR program types asked about varied between the two surveys and based on C&I customer size to ensure questions were relevant for the respondent. The questions included a general description of the program participation parameters (e.g., event duration, typical event times, maximum number of events, peak period hours) and financial incentive or rate details based on typical financial benefits offered by Michigan utilities for the given DR program type.

Table 2-11 and Table 2-12 summarize DR willingness to participate results from the residential and C&I surveys. Results from these questions were used to develop steady-state participation assumptions after the programs mature, further discussed in Section 2.5.2.

Table 2-11. Residential Willingness to Participate in DR Programs and Rates

DR Program Type	Incentive Detail	n	% Likely to Participate (Rating of 4-5 on 5-Point Scale)
BYOT	One-time $75 sign-up bonus plus $25 per season	159	27%
	One-time $50 sign-up bonus, plus $25 per season	43	70%
	One-time $100 sign-up bonus, plus $25 per season	101	11%
BYOT plus Energy Efficiency Incentive	Rebate of $175 for thermostat purchase and $25 for each enrolled thermostat per season	393	22%
	Rebate of $150 for thermostat purchase and $25 for each enrolled thermostat per season	86	80%
	Rebate of $200 for thermostat purchase and $25 for each enrolled thermostat per season	259	11%
CPP	$5 monthly bill savings per thermostat or $25 total per thermostat for the summer season	555	18%
CPP with Thermostat	Free thermostat + $5 monthly bill savings per thermostat or $25 total per thermostat for the summer season	379	12%
PTR	$25 per summer by reducing approximately 20% of your energy usage during peak demand periods	564	25%
EV Control	Not provided	301	11%
Battery Control	Not provided	290	16%

Source: Guidehouse analysis

Table 2-12. C&I Willingness to Participate in DR Programs and Rates

DR Program Type	Incentive Detail	n	% Likely to Participate (Rating of 4-5 on 5-Point Scale)
Capacity Reduction	$25/kW capacity payment, plus an additional 5 cents/kWh for actual reduction during the event	22	9%
	$20/kW capacity payment, plus an additional 5 cents/kWh for actual reduction during the event	2	100%
	$30/kW capacity payment, plus an additional 5 cents/kWh for actual reduction during the event	14	14%
Demand Bidding	30 cents/kWh payment based on actual reduction during the event	38	16%
	25 cents/kWh payment based on actual reduction during the event	6	50%
	35 cents/kWh payment based on actual reduction during the event	24	4%
BYOT	One-time $75 sign-up bonus plus $25 per season for each enrolled thermostat	124	30%
	One-time $50 sign-up bonus plus $25 per season for each enrolled thermostat	37	84%
	One-time $100 sign-up bonus plus $25 per season for each enrolled thermostat	75	8%
Energy Efficiency and BYOT	One-time discount of up to $175 for the purchase of a smart thermostat and $25 per season for each enrolled thermostat	275	19%
	One-time discount of up to $150 for the purchase of a smart thermostat and $25 per season for each enrolled thermostat	53	81%
	One-time discount of up to $200 for the purchase of a smart thermostat and $25 per season for each enrolled thermostat	171	11%
CPP	Savings of 10% or higher on electricity bill in relation to standard rate	470	19%
CPP w/ free smart thermostat	Savings of 10% or higher on electricity bill in relation to standard rate plus a free smart thermostat	255	17%
PTR	Earn around $50 per summer by reducing approximately 20% of your energy usage during the peak demand periods	408	21%
Battery Control	Not provided	470	14%

Source: Guidehouse analysis

2.4.5 COVID-19 Pandemic Impacts

The survey asked customers to provide feedback on the impacts of the COVID-19 pandemic on their DR program participation decision-making. In aggregate, the pandemic has had little to no impact on customer decision making around participation in DR programs. More than half (62%) of residential customers said they are just as likely to participate in DR; some customers said they were less likely (22%) and a similar proportion of customers said they were more likely (15%) to participate in DR. Similarly, more than half (60%) of C&I customers said they are just as likely to participate in DR; some customers said they were less likely (25%) and a similar proportion of customers said they were more likely (15%) to participate in DR. Based on these survey results, Guidehouse did not adjust the model scenarios due to the minimal, self-reported impact of the pandemic on customer decision making around participation in DR programs.

2.5 Characterization of Demand Response Options

2.5.1 Key Assumptions for DR Potential and Cost-Effectiveness Assessment

The final step in our assumptions development process was to estimate programmatic inputs such as participation rates, unit load reductions and costs for the DR options. These are key variables that feed the DR potential and cost calculations.

Participation assumptions in DR options are derived from the primary research conducted as part of this study which included online surveys of residential and C&I customers to assess customer awareness of different types of DR options and their willingness to enroll in DR programs. The survey also assessed customer willingness to adopt joint EWR-DR technologies such as smart thermostats. Participation assumptions for DR options not included in the survey were based on benchmarking with similar programs offered by other utilities. The primary research approach and results are described in Section 2.4.

Assumptions for other key variables such as unit impacts and costs necessary for potential and cost calculations were based on current pilot/program experiences from the participating utilities' service territory,[30] similar DR potential studies and program performance data/information from DR programs in other jurisdictions, and other established secondary information sources. Table 2-13 summarizes the key DR potential and cost estimation variables considered in this study.

Table 2-13. Key Variables for DR Potential and Cost Estimates

Key Variables	Description
Participation Rates	• Percentage of eligible customers enrolled in DR programs by DR options, DR suboptions, customer segment, and building types. • Participation ramp (rate at which the program ramps up to steady-state participation over a specified period).
Unit Impacts	• kW reduction per device (typically for DLC). • % of enrolled load by end-use/total facility (for non-DLC options). • % of total residential load for Behavioral DR.
Costs	• One-time fixed costs related to program development. • One-time variable costs for customer recruitment and program marketing, equipment installation and enablement. • Recurring fixed and variable costs such as annual program admin. costs, customer incentives, O&M, etc.
Global Parameters	Program Lifetime, Discount Rate, Inflation Rate, Line Losses, Avoided Costs

Source: Guidehouse

[30] Michigan utilities provided information about ongoing and planned DR activities. Guidehouse incorporated that information in building the potential estimates and inform assumptions around potential estimation. Detailed documentation of the basis for assumptions is presented in the input assumptions documentation file provided to MPSC.

Guidehouse calculated achievable potential for the DR options according to the following formula:

1. Potential for DLC suboptions is calculated as follows (where unit impacts are represented as "kW reduction per device"):

   No. of eligible customers x Participation Rate (% of eligible customers) x No. of devices per participant x Unit Impact (kW reduction per enrolled device)

2. Potential for all other non-DLC suboptions is calculated as follows (where unit impacts are represented as "% reduction in enrolled load"):

   Total eligible load x Participation Rate (% of eligible load) x Unit Impact (% of enrolled load)

In addition to the potential estimates, Guidehouse developed annual and levelized costs by DR options and suboptions and conducted cost-effectiveness assessment of these options. Development of DR program annual and levelized costs involve itemization of the various cost components such as program development costs, equipment costs, participant marketing and recruitment costs, annual program administration costs, O&M costs, product lifetimes, discount rate, and inflation rates.

2.5.2 Participation Assumptions

The DR participation assumptions are based on the residential and C&I survey results for DR options that were included in the survey. Participation assumptions for DR options not included in the survey are based on benchmarking with similar programs offered by other utilities. The Guidehouse team drew on its industry knowledge and expertise, as well as well-established secondary information sources such as publicly available DR potential studies and evaluation reports from other jurisdictions to develop these assumptions.

The participation assumptions are developed by customer segment and DR option based and represent assumed "most likely" or "achievable" participation rates in these options based on assumed incentive levels by program type and customer segment. These participation levels are assumed to be reached after the program fully ramps up. In the primary data collection, the surveys collected information about customers' willingness to participate in various DR offerings, which were shown in Table 2-8.

To convert categorical responses to numerical values, Guidehouse assumed that a certain proportion of customers with each response would ultimately be willing to participate in a DR program. Guidehouse applied the conversion factors listed in Table 2-14 to the survey responses to derive the steady-state participation for the DR options presented in the survey. Where available, survey results assessing willingness to participate at higher incentive levels are incorporated in the Aggressive Scenario.

Table 2-14. Willingness to Participate Conversion Factors

Response	Percent Expected to Participate
Not at all likely	0%
Slightly likely	25%
Somewhat likely	50%
Very likely	75%
Extremely likely	100%

Source: Guidehouse analysis

Because the results represent incremental potential beyond the amount of DR already deployed, the steady-state participation factor was adjusted to account for the number of participants currently enrolled in DR programs. The current enrollment information in DR programs was sourced from information provided by the utilities and program evaluations. In addition to the steady-state participation assumptions, Guidehouse developed ramp rate assumptions by DR option and customer segment. The ramp rate represents the rate at which the program ramps up to reach the steady-state participation levels and is based on existing program experience in the industry.

In addition to specifying steady-state participation and ramp assumptions by DR option and customer segment, Guidehouse developed suboption branches under a DR option that specify the type of control and the associated end-use that is being controlled. Table 2-3 shows how the DR suboptions map to the different DR options considered in the analysis. The suboptions under a particular DR option are mutually exclusive and the saturation of control technologies specified in the DR suboptions determined customer eligibility for those suboptions.

DR incentives and DR program awareness rates from the survey were integrated into the EWR adoption model to account for increased adoption of DR-enabled EWR technologies. The incorporation of these program design inputs results in reduced customer simple paybacks for specific measures with a DR incentive option weighted by the awareness of DR options as determined through Guidehouse primary research. To avoid double counting, only the EWR-specific incentive portion for these measures is included in budget and UCT calculations in the EWR study. Where applicable, the DR control strategy eligibility is based on saturation results from the EWR study for DR-enabling technologies, namely Energy Management and Control System (EMCS), smart thermostats, and advanced lighting controls. For example, C&I customers with EMCS are assumed to be eligible for Auto-DR HVAC control while the remaining are under manual HVAC control. Similarly, customers with smart thermostats are eligible for the Bring-Your-Own-Thermostat programs, while the remaining customers are eligible for switch-based HVAC controls.

Guidehouse also accounted for participation overlaps among the different DR programs in estimating potential. The participation hierarchy helps avoid double counting of potential through common load participation across multiple programs and is necessary to arrive at an aggregate potential estimate for the entire portfolio of DR programs. The incentive-based DR options discussed in Section 2.3.1 and presented in Table 2-2 are placed above the pricing options in the participation hierarchy. However, in cases where default TOU rates are offered to customers, the TOU rates are placed at the top of the hierarchy and incremental impacts from other DR options for customers on default TOU rates is considered. Within the incentive-based and pricing DR options, the customer eligibility for participation across multiple DR options that target the same customer segment and load is accounted for such that the same customer segment and load is not considered eligible for multiple DR options and suboptions.

2.5.3 Unit Impact Assumptions

The unit impacts specify the amount of load that could be reduced during a DR event once customers are enrolled in a DR program. Unit impacts can be specified either directly as "kW reduction per participant" or as "% of enrolled load."

For the DLC options and suboptions, unit impacts were typically specified as kW reduction for each suboption representing control technology and end-use combination. For the non-DLC options, unit impacts are specified as "% of enrolled load" for each suboption. For example, for C&I Capacity Reduction, unit impacts were developed by DR suboption as the unit impact values are tied to the end-uses and the type of control. For example, the load reductions associated with Manual HVAC control and Auto-DR HVAC control are different and are specified accordingly.

The unit impact assumptions for DR programs offered by Michigan utilities were sourced from program data provided by utilities and program EM&V reports. The unit impacts for the remaining DR options and suboptions were informed by similar programs offered by other utilities and from well-established secondary information sources.

2.5.4 Program Costs and Related Assumptions for Cost-Effectiveness

Guidehouse developed detailed itemized cost assumptions for each DR option to assess annual program costs and calculate levelized costs for each option. These cost calculations feed into the cost-effectiveness assessment of DR options.

The cost assumptions fall into the following broad categories:

- **One-time fixed costs**, specified in terms of $/DR option which include the program start-up costs, including for example, the software and IT-infrastructure related costs and associated labor time/costs (in terms of FTEs) incurred to set up the program.
- **One-time variable costs**, which include marketing/recruitment costs for new participants, metering costs if required, and all other costs associated with control and communications technologies to enable the active load reduction at participating sites. The enabling technology cost is specified either in terms of "$/new participant" on a per site basis or as "$/kW of enabled load reduction" on a participating load basis[31].
- **Annual fixed costs,** specified in terms of $/yr., which primarily includes FTE costs for annual program administration and ongoing information technology (IT) related costs not included in the one-time fixed category above.
- **Annual variable costs,** which primarily includes customer incentives, specified either as a fixed monthly/annual incentive amount per participant ($/participant), or in terms of load reduction ($/kW reduction), depending on the program type. It also includes additional O&M costs that may be associated with servicing technology installed at customer premises and recurring communication costs.

[31] The enabling technology costs represents the incremental costs associated with controls and communications for making the device DR-enabled.

Other than the itemized program costs, the other key variables related to the cost-effectiveness calculations in the model are the following:

- **Nominal discount rate** of 7.19%, used for net present value (NPV) calculations.
- **Electric line loss** between 6% and 8% and **natural gas line loss** between 0.1% and 2.3%, depending on customer segment, which is used to bring up the potential at customer meter to the generator for benefits calculations and cost-effectiveness assessment.[32]
- **Electric reserve margin** of 9.6% is based on the MISO reserve margins and is used to account for additional DR benefits at the generator.

For assessing the electric DR benefits, Guidehouse used weighted averages of avoided generation capacity, avoided transmission capacity costs, and avoided energy costs provided by the utilities and Cost of New Entry (CONE) values. Guidehouse calculated the Upper Peninsula avoided generation capacity costs as 50% of CONE.[33] Annual costs were allocated to each season proportional to the amount of potential in each season, and cost-effectiveness screening was conducted with Summer costs and benefits. Cost-effectiveness was calculated for summer for each region and DR option and is based on the Utility Cost Test (UCT). The DR study did not conduct cost-effectiveness screening for natural gas DR options as natural gas avoided costs for valuing DR benefits was not available.[34] Table 2-15 summarizes the benefits and costs considered in the cost-effectiveness assessment of DR options.

Table 2-15. Summary of Benefits and Costs in DR Analysis

Benefits	Costs
Avoided Generation Capacity Costs	Program Development Cost
Avoided T&D Capacity Costs	Program Administrative Cost
Avoided Energy Costs	Program Delivery Cost
	Marketing & Recruitment Cost
	Technology Enablement Cost
	O&M Cost
	Incentives

Source: Guidehouse analysis

The cost-effectiveness assessment is conducted over the 2021-2040 timeframe. Only DR options that had a UCT benefit-to-cost ratio of 0.8 or greater were deemed cost-effective and included in the potential estimates. A cost-effectiveness override was applied to DR suboptions that correspond to existing utility DR offerings to include potential from these suboptions in the final results.

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[32] The line loss assumptions were developed weighting the results from DTE's and Consumers' line loss studies by utility sales data for the Lower Peninsula and the Upper Peninsula. For additional detail, please refer to the EWR report.

[33] Per email communication with UPPCO.

[34] Guidehouse engaged with Michigan utilities to request natural gas avoided costs for valuing DR benefits. Utilities indicated that natural gas avoided costs were not available and therefore Guidehouse did not undertake any cost-effectiveness assessment of natural gas DR options.

3. Demand Response Potential Assessment Results

This section presents DR potential and costs results based on the approach described in Section 2. Results are presented for the three scenarios discussed in the previous section in the following order:[35]

- Cost-effectiveness assessment results with benefit-to-costs results by the following:
  - Benefit-cost ratios of DR options
  - Comparison of cost-effectiveness results across all three scenarios
- Achievable potential results by the following:
  - DR option
  - DR suboption[36]
  - Customer segment
  - Scenario
- DR program cost results by the following:
  - Annual program costs
  - Levelized costs and supply curves

3.1 Cost-Effectiveness Assessment Results

The DR potential and cost analysis first assessed cost-effectiveness of summer electric DR options for the Reference Scenario. It then assessed cost-effectiveness under the Carbon Price Scenario and Aggressive Scenario (the Aggressive Scenario represents higher incentive costs and associated higher participation levels; the Carbon Price Scenario assumes higher DER penetration than Reference Scenario). The study assessed cost-effectiveness of the electric DR options over 2021-2040. As discussed in Section 2.5.4, cost-effectiveness screening was not conducted for natural gas measures.

3.1.1 Reference Scenario Cost-Effectiveness Results

Table 3-1 shows the cost-effectiveness results of summer electric DR options under the Reference Scenario for the Lower Peninsula and the Upper Peninsula. For the Lower Peninsula, all DR options other than Smart Appliances Control and load reduction using Thermal Energy Storage are not cost-effective. For the Upper Peninsula, in addition to these two DR options, Direct Load Control using switches and EV managed charging were not cost-effective.[37] The cost-effectiveness assessment used a 0.8 benefit-cost ratio threshold under UCT to determine which DR options were cost-effective.

[35] Detailed potential and cost results are included in the excel-based results dashboards accompanying this report.

[36] Only presented for summer electric for both the Lower Peninsula and the Upper Peninsula; suboption level results for winter electric and for winter natural gas can be found in the in the excel-based results dashboards accompanying this report.

[37] As discussed previously in Section 2, the avoided costs for the Upper Peninsula are lower than the avoided costs for the Lower Peninsula.

Table 3-1. Reference Scenario Benefit-Cost Ratios of DR Options (Electric) for Lower Peninsula and Upper Peninsula (Summer)

DR Options	Lower Peninsula	Upper Peninsula
	UCT Benefit-Cost Ratio (2021-2040)	
Real Time Pricing (RTP)	12.3	17.0
Time-of-Use (TOU)	11.4	11.8
C&I Demand Bidding	5.0	3.9
C&I Capacity Reduction	3.7	3.0
Critical Peak Pricing (CPP)	3.4	2.7
Voltage Optimization (VO)	2.0	1.4
Bring Your Own Thermostat (BYOT)	1.8	1.3
Behind-the-Meter (BTM) Battery Dispatch	1.6	1.2
Behavioral DR	1.5	1.1
Peak Time Rebate (PTR)	1.1	1.0
Electric Vehicle (EV) Managed Charging	0.9	0.5
Direct Load Control (DLC)-Switch	0.8	0.5
Smart Appliances Control (Bring Your Own Device)	0.2	0.2
Thermal Energy Storage (TES)	0.1	0.1

Source: Guidehouse analysis

3.1.2 Comparison of Cost-Effectiveness Results by Scenarios

Table 3-2 and Table 3-3 show cost-effectiveness results across the three scenarios for all DR options for the Lower Peninsula and the Upper Peninsula, respectively. The cost-effectiveness results do not change between the Reference Scenario and the Carbon Price Scenario. The avoided capacity costs are the same between the Reference Scenario and Carbon Price Scenario, which is the primary driver of DR benefits.[38] The Carbon Price Scenario modeled higher adoption of EVs and BTM batteries, but other than that, costs and impact assumptions remained unchanged between the Reference Scenario and the Carbon Price Scenario. Therefore, the benefit-cost ratios are the same between the two scenarios, except for very slight changes to the benefit-cost ratios for the EV and BTM Battery options.

The Aggressive Scenario assumed higher participation levels in DR options under higher incentive levels, which leads to lower benefit-cost ratios. For the Aggressive Scenario, the two DR options that are not cost-effective for the Lower Peninsula are DLC-switch and EV Managed Charging, in addition to the two DR options (Smart Appliances Control and TES) that were not cost-effective under the Reference Scenario. For the Upper Peninsula, cost-effectiveness screening remains unchanged between the Aggressive Scenario and the Reference Scenario.

[38] Even though the avoided energy costs are higher in the Carbon Price Scenario than the Reference Scenario, the avoided energy costs have relatively much smaller contribution to DR benefits than avoided capacity costs.

Table 3-2. Benefit-Cost Ratio Comparisons by Scenarios of DR Options (Electric) for Lower Peninsula (Summer)

DR Option	Reference	Aggressive	Carbon Price
	UCT Benefit-Cost Ratio (2021-2040)		
Real Time Pricing (RTP)	12.3	7.2	12.3
Time-of-Use (TOU)	11.4	11.3	11.4
C&I Demand Bidding	5.0	3.8	5.0
C&I Capacity Reduction	3.7	3.2	3.7
Critical Peak Pricing (CPP)	3.4	3.2	3.4
Voltage Optimization (VO)	2.0	2.4	2.0
Bring Your Own Thermostat (BYOT)	1.8	1.5	1.8
Behind-the-Meter (BTM) Battery Dispatch	1.6	1.2	1.7
Behavioral DR	1.5	1.5	1.5
Peak Time Rebate (PTR)	1.1	0.9	1.1
Electric Vehicle (EV) Managed Charging	0.9	0.7	0.8
Direct Load Control (DLC)-Switch	0.8	0.7	0.8
Smart Appliances Control (Bring Your Own Device)	0.2	0.2	0.2
Thermal Energy Storage (TES)	0.1	0.1	0.1

Source: Guidehouse analysis

Table 3-3. Benefit-Cost Ratio Comparisons by Scenarios and DR Options (Electric) for Upper Peninsula (Summer)

DR Option	Reference	Aggressive	Carbon Price
	UCT Benefit-Cost Ratio (2021-2040)		
Real Time Pricing (RTP)	17.0	11.3	17.0
Time-of-Use (TOU)	11.8	11.4	11.6
C&I Demand Bidding	3.9	3.1	3.9
C&I Capacity Reduction	3.0	2.4	2.7
Critical Peak Pricing (CPP)	2.7	2.9	3.0
Voltage Optimization (VO)	1.4	1.4	1.4
Bring Your Own Thermostat (BYOT)	1.3	1.2	1.3
Behind-the-Meter (BTM) Battery Dispatch	1.2	0.9	1.2
Behavioral DR	1.1	1.1	1.1
Peak Time Rebate (PTR)	1.0	0.8	1.0
Electric Vehicle (EV) Managed Charging	0.5	0.4	0.6
Direct Load Control (DLC)-Switch	0.5	0.4	0.5
Smart Appliances Control (Bring Your Own Device)	0.2	0.2	0.2
Thermal Energy Storage (TES)	0.1	0.1	0.1

Source: Guidehouse analysis

3.2 Achievable Potential Results

As described previously, the potential assessment considers only cost-effective DR options and shows only incremental potential beyond the demand reduction that existing programs are achieving (includes all DR options highlighted green in Table 3-2 and Table 3-3). This section presents achievable potential results over 2021-2040, by DR option, suboption, customer segment, and scenario. It has also been organized by fuel type, season, and region.

3.2.1 Reference Scenario Achievable Potential by DR Option

This section shows the achievable potential by DR options for both electric and natural gas and across both summer and winter for the Lower Peninsula and the Upper Peninsula. In the electric achievable potential graphs, only cost-effective options are presented. For natural gas, all options are presented.

3.2.1.1 Lower Peninsula Electric Summer Achievable Potential by DR Option

Figure 3-1 shows the MW breakdown of achievable potential by option for summer for the Lower Peninsula. The achievable potential increases steadily from around 300 MW of summer peak reduction potential in 2021 (translates to around 2% reduction in summer peak demand forecast in 2021 for the Lower Peninsula) to around 1,850 MW of peak demand in 2040 (translates to around 10% reduction in summer peak demand forecast in 2040 for the Lower Peninsula). The top four DR options that constitute over 80% of the total cost-effective potential are – C&I Capacity Reduction, BYOT, CPP, and DLC-switch.

C&I Capacity Reduction, which targets Large and Extra-Large C&I segments, has highest contribution in the potential once all programs ramp up and reach steady state participation levels. It constitutes 25% of the total potential in 2040 at 465 MW.

The BYOT DR option has second highest contribution in potential in 2040. The BYOT potential is projected to increase significantly from around 20 MW in 2021 to 390 MW in 2040, constituting 21% share in total potential in 2040. This increase follows the growth rate in adoption of smart thermostats from the EWR analysis. Note that, as described previously in Section 2.5.2, the adoption of smart thermostats considered both EWR and DR benefits in customer decision making to purchase a smart thermostat.

CPP has third highest contribution at 20% of the total potential in 2040 (374 MW peak reduction potential). CPP has highest contribution toward total potential in the early years (at approximately 30%-35%) as the programs gradually ramp up but is overtaken by C&I Capacity Reduction and BYOT in the later years. The higher growth rate in potential over the first 5-year period represent a typical 5-year ramp-up for new DR offerings, at which point the programs reach steady-state participation levels. Potential from pricing options such as CPP, PTR, and RTP grows in the initial years and then declines over time because they are placed lower in the participation hierarchy relative to the incentive-based options such as DLC, BYOT, C&I Capacity Reduction, Demand Bidding, and others.[39] As more customers enroll in incentive-based DR options, the subset of customers eligible for pricing options decreases.

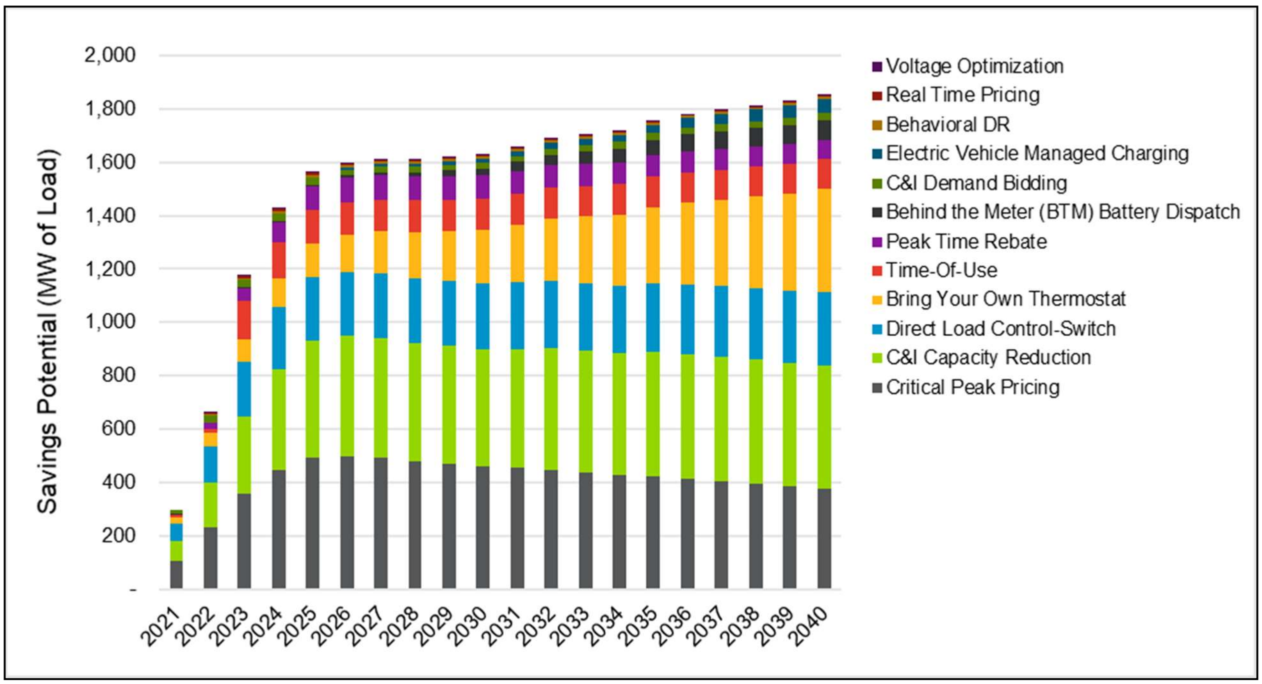
The DLC-Switch option, which includes space cooling and water heating control via load control switches, has fourth highest contribution in the potential at 15% of the total (around 270 MW) in

[39] Please refer to Section 2.3.1 and 2.5.2 for discussion on classification of DR options and participation hierarchy.

2040. The contribution from DLC-switch progressively declines over the 2021-2040 timeframe as BYOT share increases steadily over this time period.

Among the other DR options (excluding the top four discussed above), TOU and PTR have 6% and 4% share in the total potential in 2040. The potential from BTM Battery Dispatch is projected to increase steadily from around 2 MW in 2021 to around 75 MW in 2040. This is driven by a steady increase in BTM battery adoption by customers over 2021-2040 (discussed previously in Section 2.2.3). BTM Battery Dispatch has a 4% share in total potential in 2040. Similarly, potential from EV Managed Charging is projected to grow steadily from being non-existent in 2021 to around 50 MW in 2040, which constitutes approximately 3% share in the total in 2040. Similar to BTM batteries, the increase in EV Managed Charging potential over time is driven by the EV adoption projections presented in Section 2.2.4. Other DR options such as Demand Bidding, Behavioral DR, RTP and Voltage Optimization each have less than 1% share in total potential in 2040.

Figure 3-1. Lower Peninsula Electric Summer Achievable Potential by DR Option (MW at Meter)



Source: Guidehouse analysis

3.2.1.2 Upper Peninsula Electric Summer Achievable Potential by DR Option

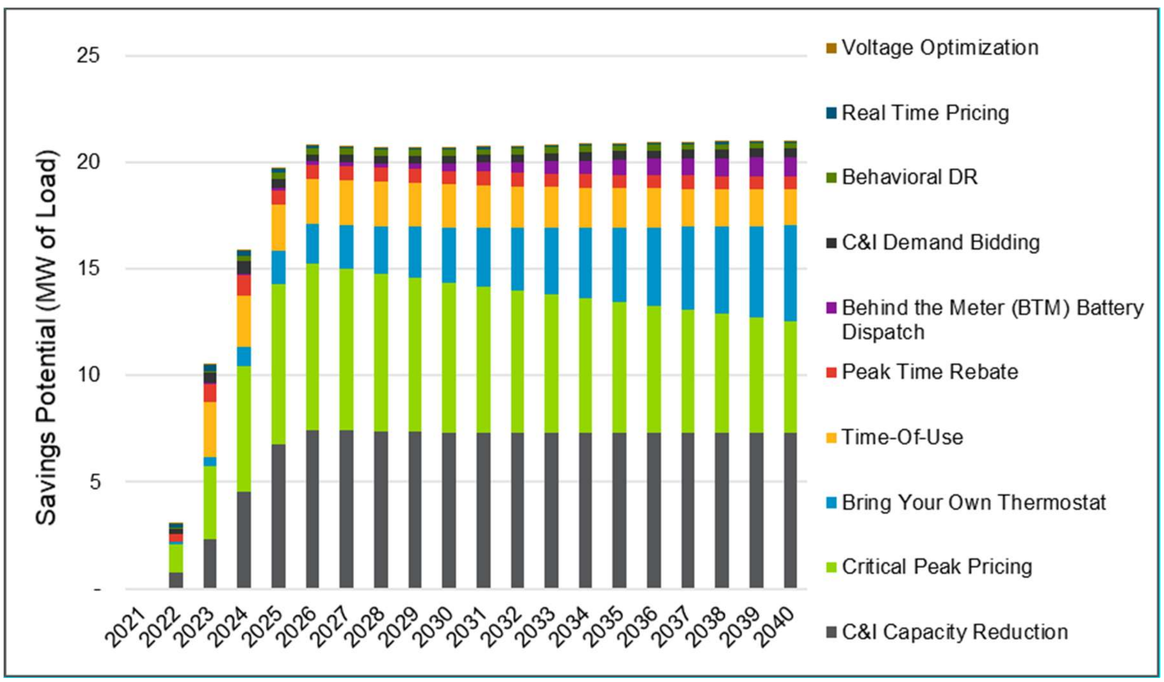
Figure 3-2 shows the MW breakdown of achievable potential by DR option for summer for the Upper Peninsula. The trends in the Upper Peninsula potential results are similar to those discussed previously for the Lower Peninsula.

The achievable potential increases steadily from around 3 MW of summer peak reduction potential in 2022 (translates to around 1% reduction in summer peak demand forecast in 2022 for the Lower Peninsula) to over 20 MW in 2040 (translates to around 6% reduction in summer peak demand forecast in 2040 for the Upper Peninsula). The top three DR options that constitute over 80% of the total cost-effective potential are – C&I Capacity Reduction, CPP, and BYOT. Unlike the Lower Peninsula, DLC-switch is not cost-effective for the Upper Peninsula.

C&I Capacity Reduction has higher contribution in potential in 2040 (35% share of total). Its potential increases steadily from less than 1 MW in 2022 to around 7 MW in 2040. CPP has second highest share in potential in 2040 at 25% of the total. CPP potential increases from 1.3 MW in 2022 (43% share in total) to over 5 MW in 2040 (25% share in total). The lowering in contribution from CPP over time is due to the steady growth in C&I Capacity Reduction and other incentive-based DR options that are placed above the pricing options in the participation hierarchy.[40] Similar to Lower Peninsula results, BYOT potential increases steadily over time from less than 0.5 MW in 2022 to around 4.5 MW in 2040, driven by higher adoption of smart thermostats from a joint EWR-DR perspective. BYOT is placed above CPP in the participation hierarchy and therefore the steady increase in BYOT potential leads to decline in CPP contribution from residential.

Among the other DR options (other than the top three discussed above), TOU has 4% share in total potential in 2040, followed by PTR with 3% share. Similar to Lower Peninsula results, DR contribution from BTM Battery Dispatch and EV Managed Charging grow steadily over time due to increasing adoption of these technologies.

Figure 3-2. Upper Peninsula Electric Summer Achievable Potential by DR Option (MW at Meter)



Source: Guidehouse analysis

3.2.1.3 Lower Peninsula Electric Winter Achievable Potential by DR Option

Figure 3-3 shows the MW breakdown of achievable potential by DR option for winter for the Lower Peninsula. Total winter potential is projected to increase from around 190 MW in 2021 to around 1190 MW in 2040. Unit impacts and baseline peak demand are lower in winter

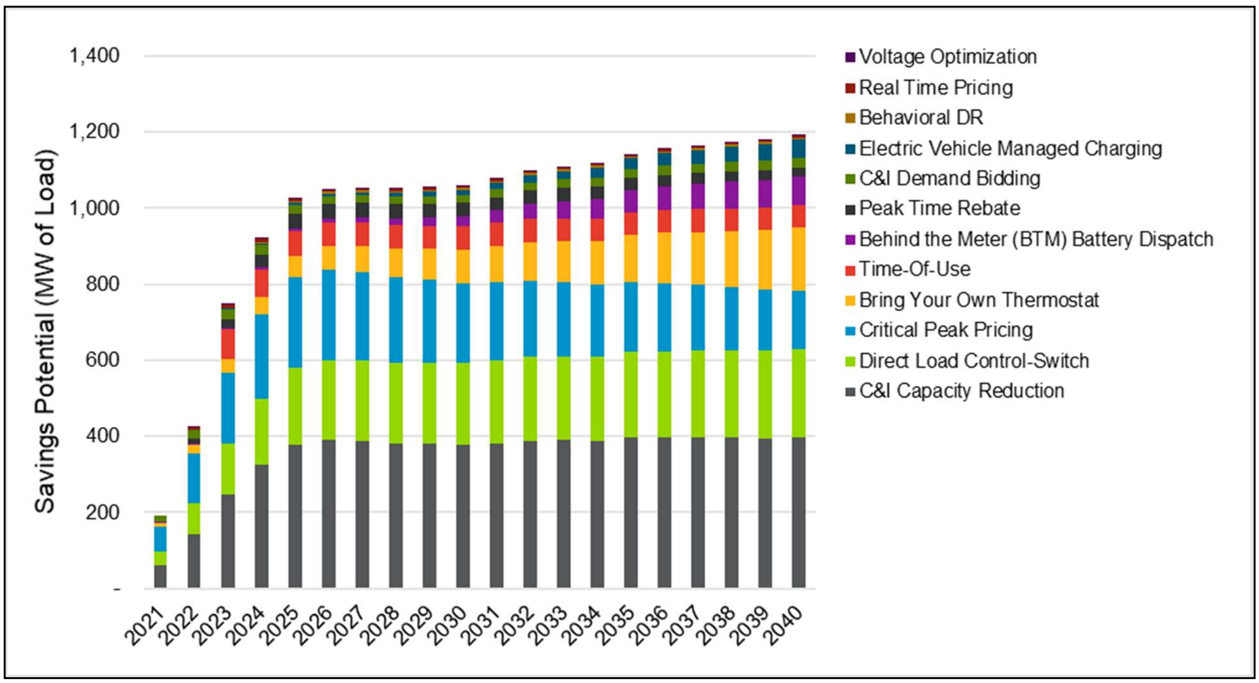
[40] Please refer to Section 2.3.1 and 2.5.2 for discussion on classification of DR options and participation hierarchy

compared to summer, thus leading to 30% to 35% lower demand reduction potential relative to summer.

The top four DR options that constitute over 80% of the total cost-effective potential are – C&I Capacity Reduction, DLC-switch (for space heating and water heating control), BYOT, and CPP. C&I Capacity Reduction from large and extra-large C&I customers has 33% share in total potential in 2040 followed by DLC-switch at 20% share. CPP and BYOT options have approximately equal share in total winter potential at around 15% share from each of these two options. Similar to the summer trends, CPP contribution first increases and then declines over time as potential from incentive-based DR options such as C&I Capacity Reduction, BYOT and DLC-switch steadily increase, which are placed above pricing options in the participation hierarchy.

Out of the remaining DR options (other than the top four discussed above), BTM Battery Dispatch potential steadily increased over time and reaches 74 MW in 2040, constituting 6% of the total winter potential in that year. TOU has 5% share in total in 2040, followed by EV Managed Charging at 4% share. The remaining DR options shown in the results have less than 5% share in aggregate in the total potential.

Figure 3-3. Lower Peninsula Electric Winter Achievable Potential by DR Option (MW at Meter)

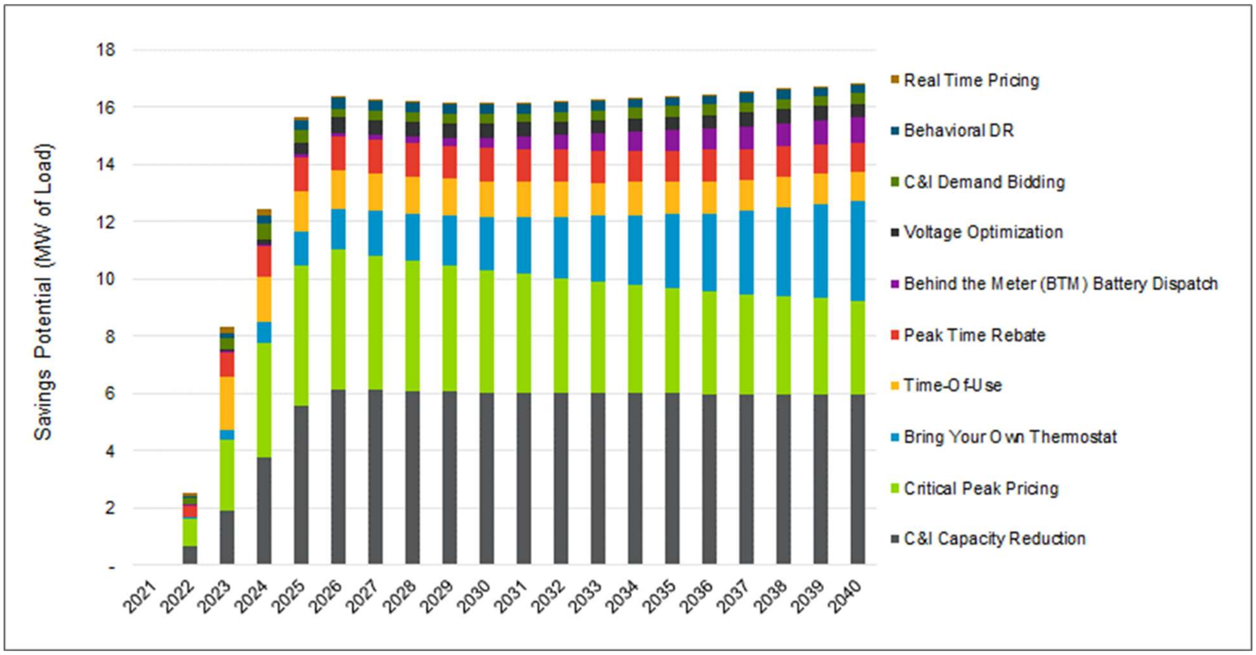


Source: Guidehouse analysis

3.2.1.4 Upper Peninsula Electric Winter Achievable Potential by DR Option

Figure 3-4 shows the MW breakdown of achievable potential by option for winter for the Upper Peninsula. Results are similar to those discussed above for the Lower Peninsula. Winter peak reduction potential is projected to grow from around 2.5 MW in 2022 to over 17 MW in 2040. The top three DR options with almost 75% contribution to total potential are – C&I Capacity Reduction, CPP and BYOT. DLC-switch is not cost-effective for the Upper Peninsula. TOU and PTR have equal share at 6% each in total in 2040. BTM Battery dispatch has 5% share in total potential in 2040.

Figure 3-4. Upper Peninsula Electric Winter Achievable Potential by DR Option (MW at Meter)



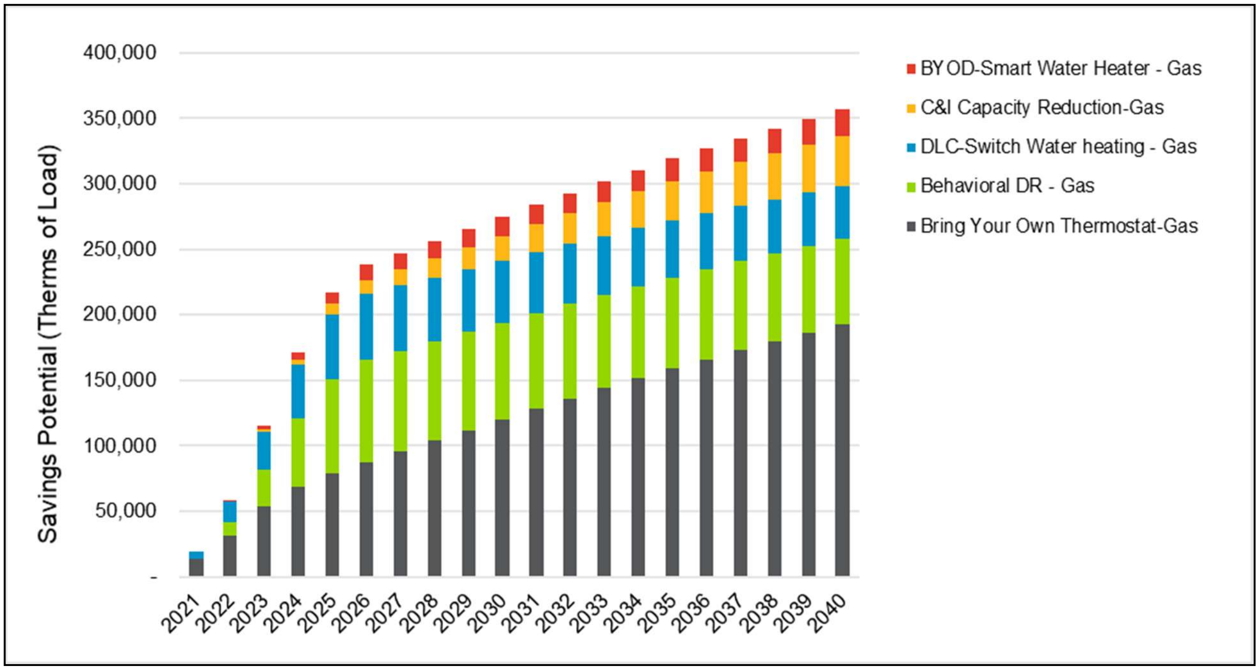
Source: Guidehouse analysis

3.2.1.5 Lower Peninsula Natural Gas Winter Achievable Potential by DR Option

The natural gas DR potential for the Lower Peninsula is projected to significantly grow from around 20,000 therms in 2021 to roughly 356,600 therms in 2040. DLC-switch water heating and BYOT are the only options in 2021, with DLC contributing 6,178 therms out of a total 20,0000 therms (31% share). In 2040, BYOT has the largest achievable potential in the Lower Peninsula with 192,435 therms (54%). There is a clear upward trend in the total potential amounts to roughly 356,600 therms. DLC-switch water heating and BYOT are the only options in 2021, with DLC contributing 6,178 MW out of a total 19,638 MW (31%). In 2040, BYOT has the largest achievable potential in the Lower Peninsula with 192,435 therms (54%). Behavioral DR for natural gas has second highest potential in 2040 at around 20% share in total. DLC-switch for water heating control and C&I Capacity Reduction for natural gas have almost equal contribution at around 10% share in total from each in 2040.

There is a clear upward trend in Figure 3-5. Similar to the electric potential, the significant growth in BYOT and C&I capacity reduction potential is driven by the increased adoption of enabling technologies, namely smart thermostats, and energy management systems. The adoption of these technologies is considered from a joint EWR-DR perspective, as is discussed previously in Section 2.5.2. The potential from Behavioral DR ramps up in the initial years and decreases slightly over time as higher penetration of EWR measures leads to decline in the natural gas baseline demand projections.

Figure 3-5. Lower Peninsula Natural Gas Winter Achievable Potential by DR Option (therms at Meter)

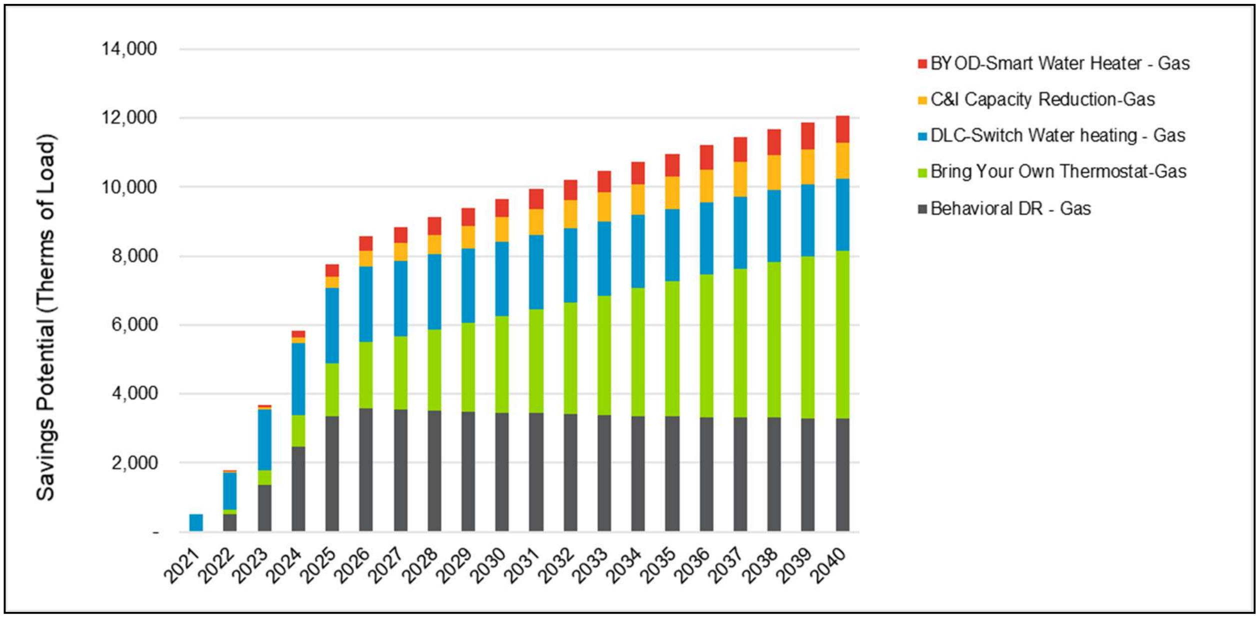


Source: Guidehouse analysis

3.2.1.6 Upper Peninsula Natural Gas Winter Achievable Potential by DR Option

The trends for the Upper Peninsula are similar to those for the Lower Peninsula. The Upper Peninsula Reference Scenario potential is 12,086 therms in 2040. DLC-switch water heating is the only option in 2021 and has a potential of 518 therms. In 2022, it has a potential of 1,090 therms (61%) out of 1,763 therms. In 2040, BYOT has the largest achievable potential in the Lower Peninsula with 4,878 therms (40%). Figure 3-6 shows the long-term natural gas winter potential for all natural gas DR options for the Upper Peninsula.

Figure 3-6. Upper Peninsula Natural Gas Winter Achievable Potential by DR Option (therms at Meter)



Source: Guidehouse analysis

3.2.2 Reference Scenario Achievable Potential by DR Suboption

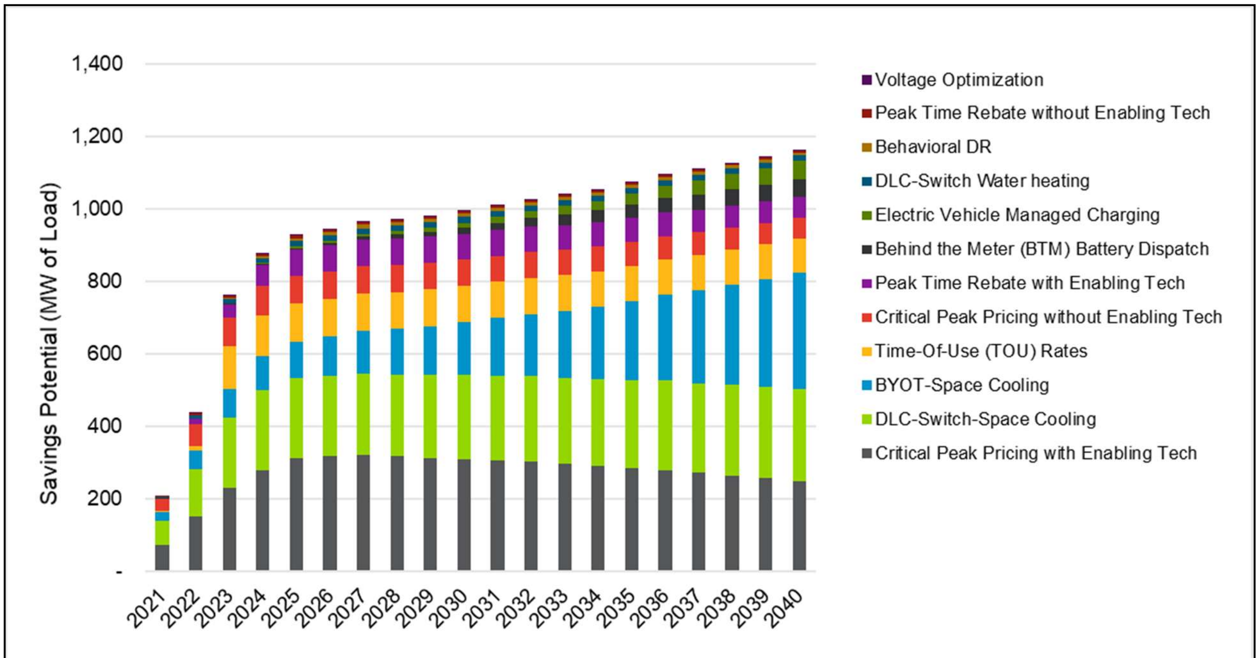
This section presents a breakdown of achievable potential by the different DR suboptions included in the analysis. The DR suboptions differentiate control technologies by customer segment under the same DR option and therefore provide greater granularity of the potential results. The results by DR suboptions are separately presented for residential and C&I customers. The residential potential results include EVs. The results by suboption are presented only for summer electric for residential and C&I customers. Suboption level results for winter electric and for natural gas are available in Appendix D, which is the excel-based results dashboard accompanying this report.

Residential Potential

3.2.2.1 Lower Peninsula Electric Summer Residential Potential by DR Suboption

Figure 3-7 shows the summer peak demand reduction potential from residential customers for the Lower Peninsula. BYOT space cooling contributes the most in 2040 with 320 MW (28%). As is evident in the figure below, the BYOT potential increases substantially with progressively higher adoption of smart thermostats. DLC-switch space cooling potential ramps up in the initial years, but beyond that the potential remains steady once the program matures. CPP with enabling technology (smart thermostats), with highest contribution in DR potential in the initial years, but its share declines over time as BYOT participation grows (CPP is placed below DLC in the participation hierarchy). These top three DR suboptions have over 70% contribution in the total residential potential. The other contributors are TOU rates (around 8% share in total), followed by PTR with enabling technology (5% share) and CPP without enabling tech (5% share). BTM Battery dispatch and EV Managed Charging each have relatively small contribution in the residential potential at 4% share from each. The remaining DR suboptions each have less than 1% share in total potential.

Figure 3-7. Lower Peninsula Electric Summer Residential Potential by DR Suboption (MW at Meter)

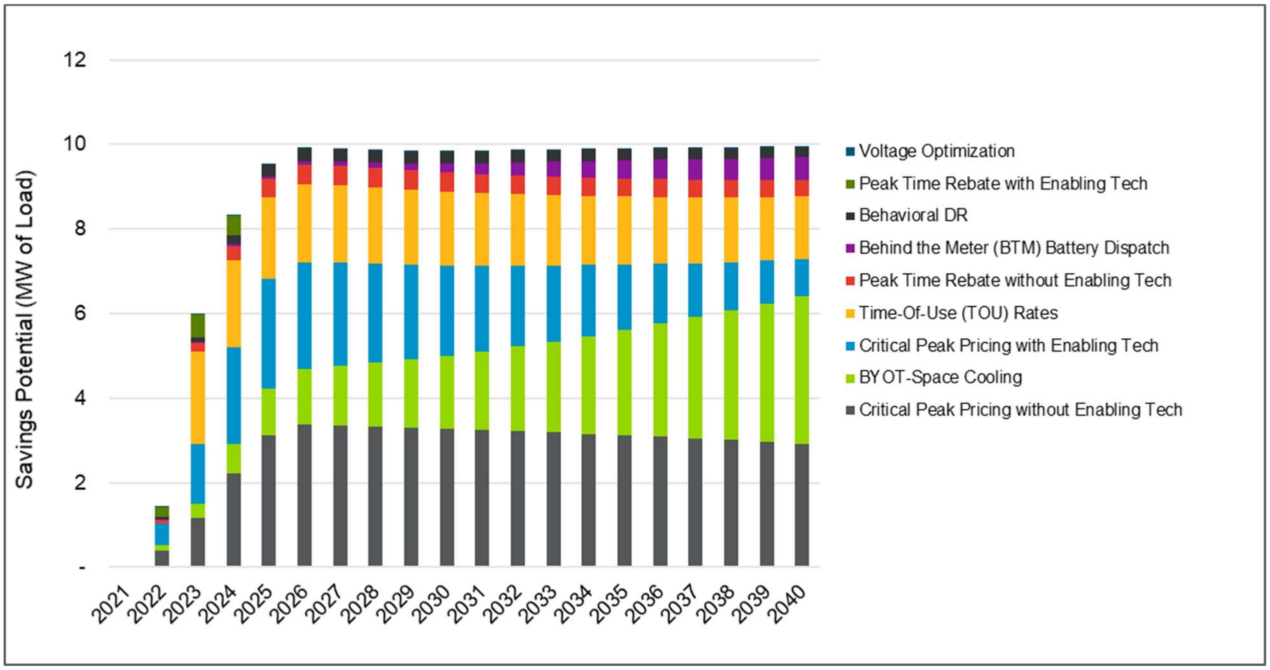


Source: Guidehouse analysis

3.2.2.2 Upper Peninsula Electric Summer Residential Potential by DR Suboption

Figure 3-8 shows the summer residential achievable potential by DR suboption for the Upper Peninsula. The trends are similar to those the for Lower Peninsula. In the early years, CPP has highest contribution, but is overtaken by BYOT as smart thermostat adoption steadily increases. TOU contribution is at 15% of the total potential in 2040. Similar to CPP, its contribution declines over time as BYOT potential increases. The other DR suboptions collectively have 10% share in total potential.

Figure 3-8. Upper Peninsula Electric Summer Residential Potential by DR Suboption (MW at Meter)



Source: Guidehouse analysis

C&I Potential

3.2.2.3 Lower Peninsula Electric Summer C&I Potential by Suboption

Figure 3-9 shows the long-term electric summer C&I achievable potential by DR suboption for the Lower Peninsula. C&I Capacity Reduction, as shown, has highest potential with 34 MW out of 90 MW in 2021 (38% share in total C&I potential); it remains the highest through to 2040 with 286 MW out of 689 MW (42% share in total C&I potential). This is because this suboption primarily applies to C&I customers with the highest peak demand (mostly extra-large C&I customers), who can provide significant contribution in the total potential.

C&I Capacity Reduction using Auto-DR for HVAC control has second highest contribution at around 100 MW potential in 2040 (15% share in total C&I potential). As is evident in Figure 3-9, the contribution from this suboption steadily increases over time, while the share of Manual HVAC control decreases (Manual HVAC control has 26% share in total potential in 2021, but its share declines steadily as Auto-DR HVAC contribution increases to less than 5% share in 2040). The progressive increase in contribution from Auto-DR for HVAC control is tied to increasing adoption of Energy Management Systems (EMS) by C&I customers from the EWR analysis. Similar to smart thermostats, the adoption of EMS by C&I customers is considered from a joint EWR-DR perspective where the customer perceives both EWR and DR benefits in adopting the technology, which effectively reduces the payback period and enhances adoption.

BYOT for C&I customers (applies to small and medium C&I customers) has third highest contribution in total potential in 2040 at around 70 MW (10% share in total C&I potential). Similar to Auto-DR for HVAC control using EMS, the potential for space cooling control using smart thermostats in small and medium commercial customer facilities is projected to increase steadily over time as smart thermostat adoption grows for these segments. Similar to smart thermostat adoption for residential, smart thermostat adoption for small and medium C&I customers was considered from a joint EWR-DR perspective and the results from EWR-DR integration show that customer adoption is enhanced through lowering of payback period when customers perceive both EWR and DR benefits from the technology.

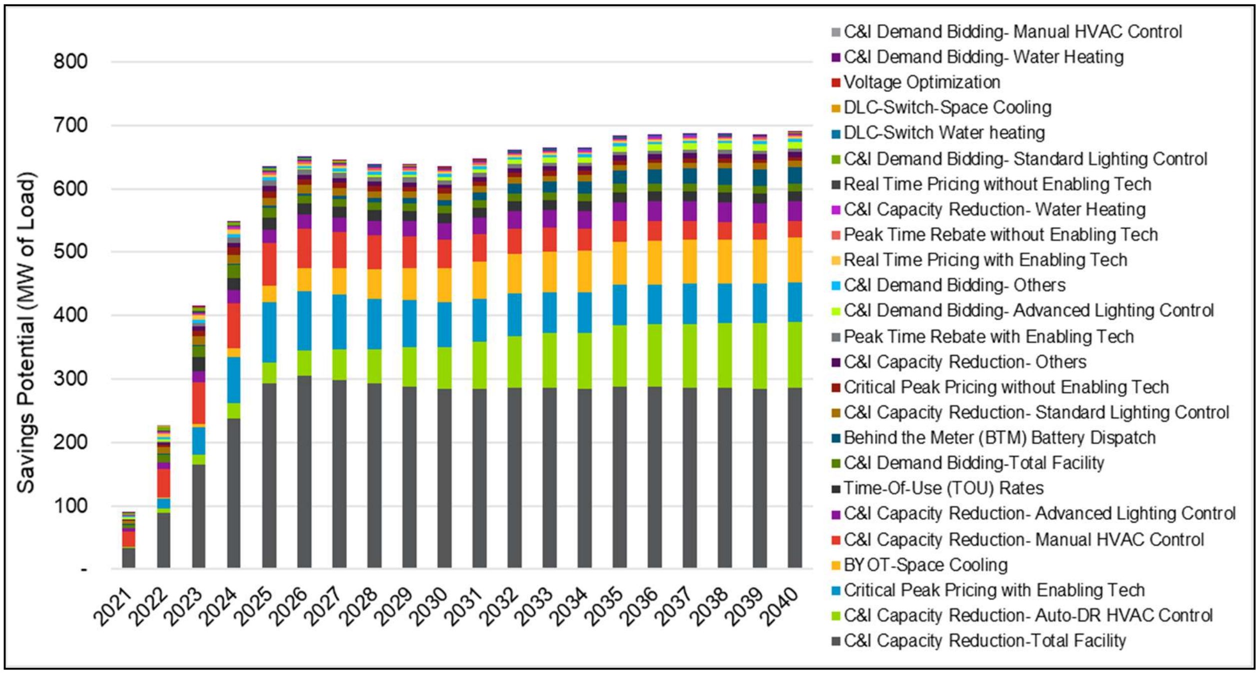
Critical Peak Pricing with enabling technology[41] has fourth highest contribution in total potential in 2040 at around 60 MW (9% share in total C&I potential). This suboption considers enhanced customer response to CPP rates when paired with enabling technology such as Auto-DR. Industry experience shows that response to CPP rates can be significantly enhanced when rates are paired with enabling technology, which is supported by the results presented here.

Load reductions associated with advanced lighting controls in C&I facilities is the fifth largest contributor to total 2040 potential (around 5% share in total). This is another example where the adoption of advanced lighting controls by C&I customers was considered from a joint EWR-DR perspective. Similar to smart thermostats and EMS, the perception of joint EWR and DR benefits from the technology reduces customer payback and enhances adoption. Therefore, we see that the contribution from this suboption steadily grows over time as customer adoption increases.

BTM Battery Dispatch is projected to have less than 5% share in total potential in 2020 (with around 25 MW potential in 2040). As previously discussed, the potential projection from this suboption is tied to battery adoption assumptions discussed in Section 2. All remaining DR suboptions (TOU, Demand Bidding, PTR, RTP, DLC suboptions) make up the remaining C&I potential.

[41] Enabling technology here refers to Auto-DR

Figure 3-9. Lower Peninsula Electric Summer C&I Potential by Suboption (MW at Meter)



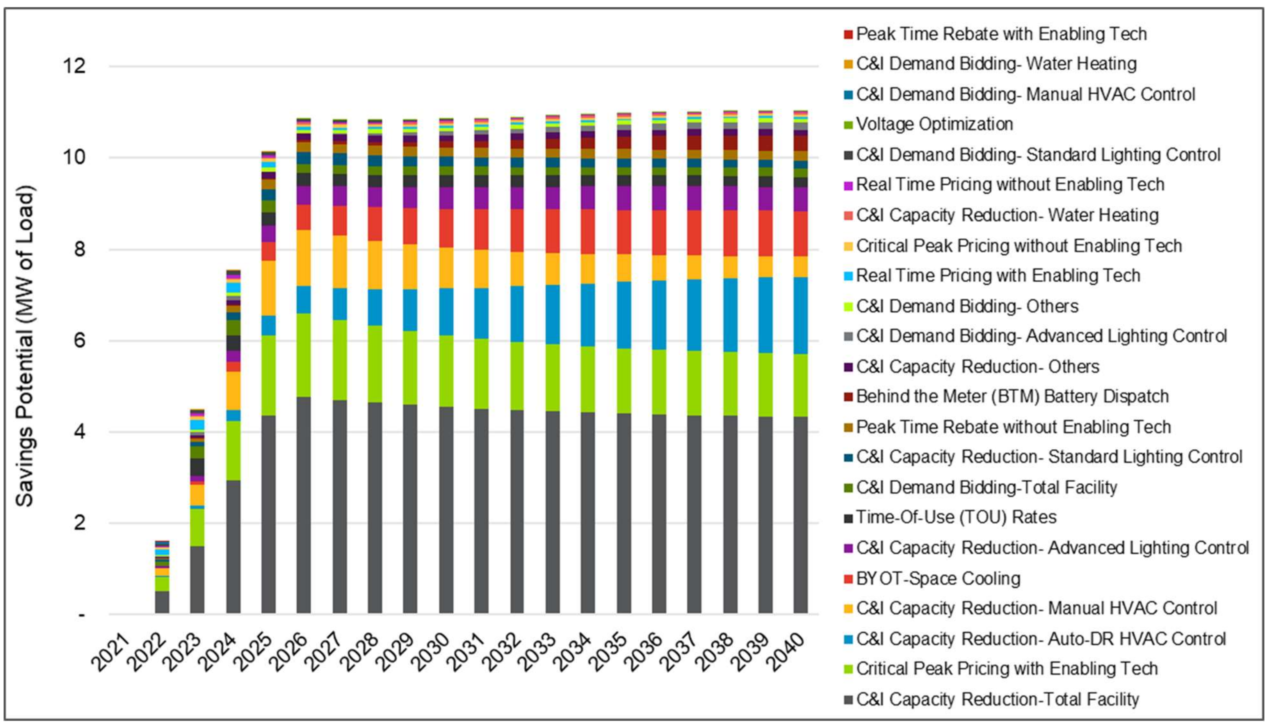
Source: Guidehouse analysis

3.2.2.4 Upper Peninsula Electric Summer C&I Potential by Suboption

Figure 3-10 shows the achievable summer peak demand reduction potential from C&I customers by DR suboption for the Upper Peninsula. The trends for the Upper Peninsula are similar to those discussed earlier for the Lower Peninsula.

C&I Capacity Reduction – Total Facility makes up a large part of the total achievable potential with 0.5 MW (32%) out of 2 MW in 2022; it remains the greatest contributor to total potential through to 2040 with 4 MW out of 9 MW (40%). Share from Auto-DR HVAC control steadily increases over time as EMS adoption by C&I customers grow (grows from 1% share in total in 2022 to 15% share in total in 2040), which leads to a decline in contribution from manual HVAC control. CPP with enabling tech grows in initial years, then remains steady and slightly goes down as contribution from incentive-based DR options grow (pricing options are placed below incentive-based options in the participation hierarchy discussed in Section 2). Contribution from BYOT (from small and medium C&I customers) and from Advanced Lighting Controls steadily increase over time as customer adoption of these technologies steadily grow based on EWR-DR integration in customer adoption.

Figure 3-10. Upper Peninsula Electric Summer C&I Potential by Suboption (MW at Meter)



Source: Guidehouse analysis

3.2.3 Reference Scenario Achievable Potential by Customer Segment

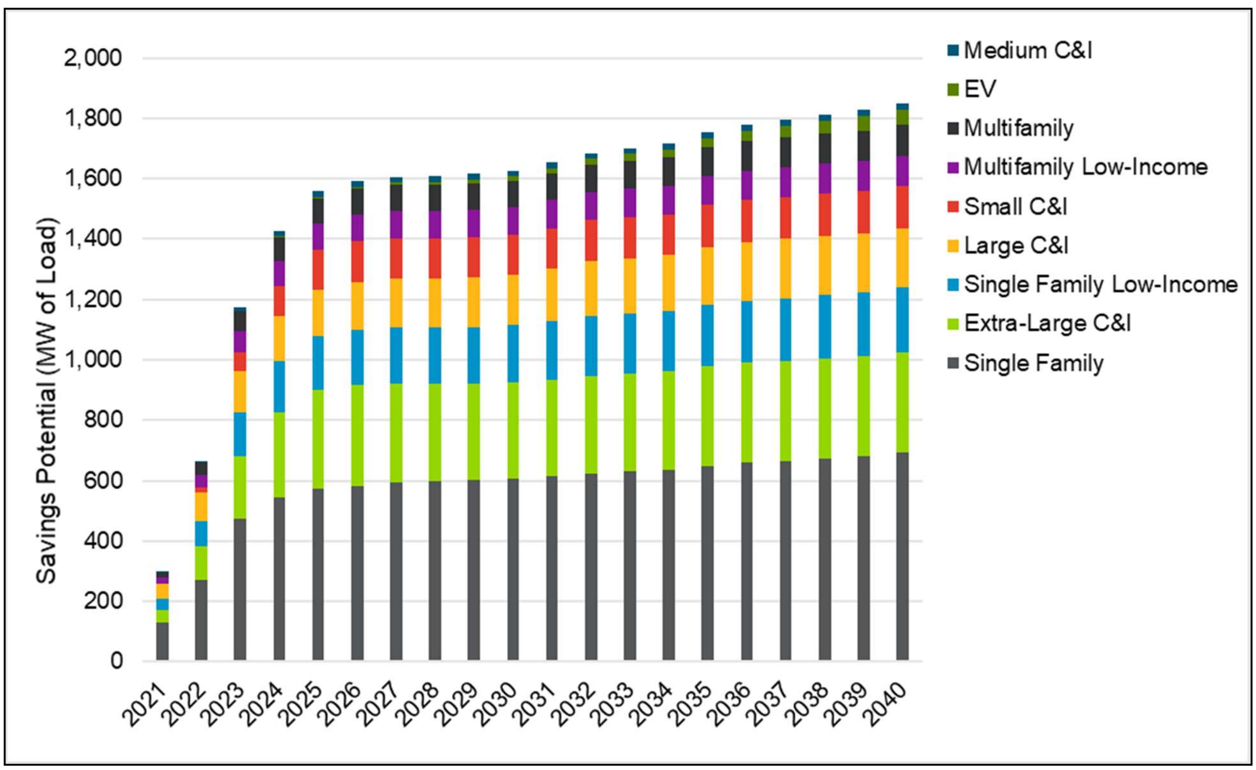
This section discusses potential results disaggregated by customer segment. It first presents the electric summer peak reduction potential by segment for Lower and Upper Peninsula, followed by natural gas winter DR potential by segment for Lower and Upper Peninsula. The winter electric potential results breakdown by customer segment are presented in the excel results dashboard accompanying this report but are omitted from the discussion of results in the report.

3.2.3.1 Lower Peninsula Electric Summer Achievable Potential by Customer Segment

Figure 3-11 shows the long-term electric summer achievable potential by customer segment for the Lower Peninsula.

Single-family contributes the most to total achievable potential with 129 MW (43%) out of a total 298 MW in 2021. Single-family continues to contribute the most in 2040, with 691 MW out of 1,849 MW (37% of total). Most of the potential is associated with BYOT, DLC-Switch, and CPP options. Extra-large C&I customers have the second highest share in total potential with around 15%-20% share in total (potential grows from about 40 MW in 2021 to 332 MW in 2040). Most of this potential is associated with C&I Capacity Reduction. Single-family low income has slightly greater than 10% share in total potential over the 2021-2040 timeframe (grows from 41 MW in 2021 to 216 MW in 2040). Contribution from large C&I customers is roughly 10% of the total (grows from 49 MW in 2021 to 196 MW in 2021). Both regular multifamily and multifamily low income have approximately equal contribution at 5% of the total. EVs are considered a separate segment and the contribution from EVs is at 3% of the total potential (EV Managed Charging potential is projected to grow from less than 1 MW in 2022 to around 50 MW in 2040). Medium C&I customers have the smallest share at 1% of the total potential.

Figure 3-11. Lower Peninsula Electric Summer Potential Results by Customer Segment (MW at Meter)

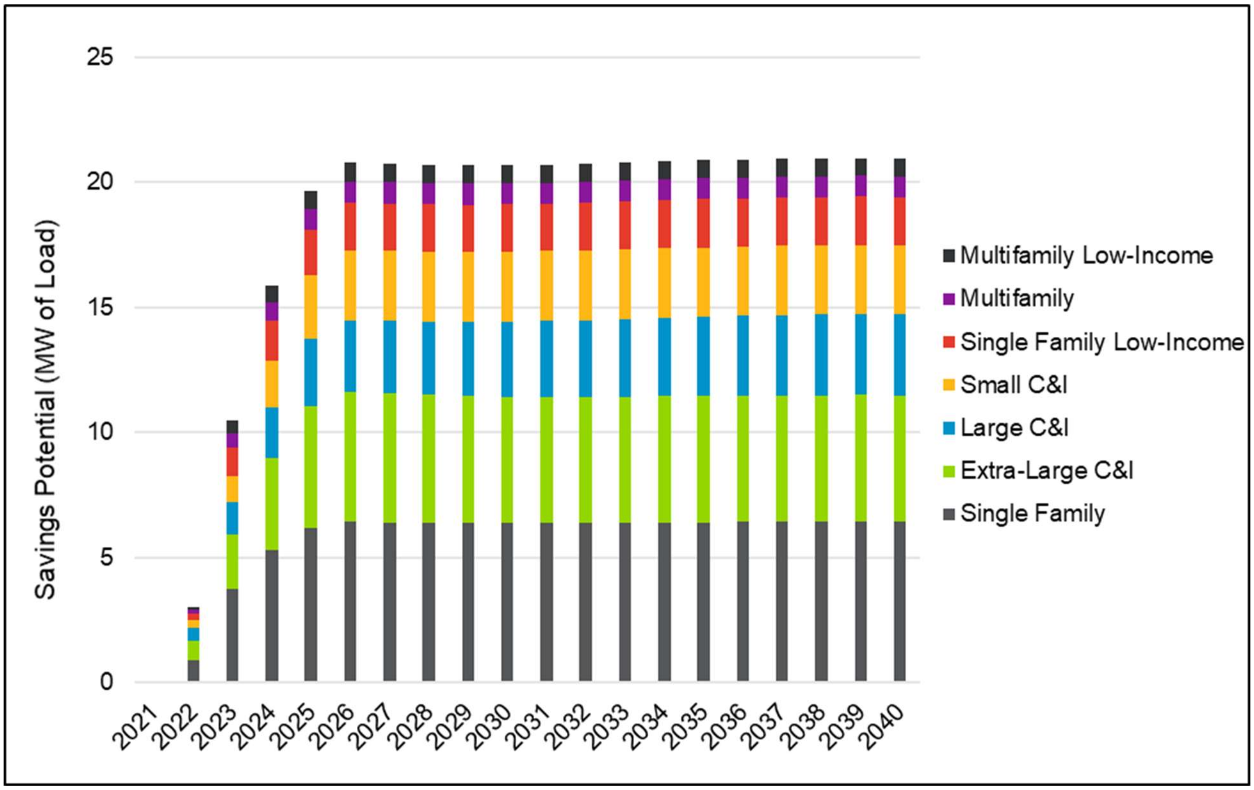


Source: Guidehouse analysis

3.2.3.2 Upper Peninsula Electric Summer Achievable Potential by Customer Segment

Figure 3-12 shows summer achievable potential by customer segment for the Upper Peninsula. The trends are similar to those shown for the Lower Peninsula. Single-family contributes the most to total potential with 30%-35% share in total (potential grows from less than 1 MW in 2022 to around 7 MW in 2040). Extra-large C&I customers have second highest contribution with approximately 25% share in total, primarily from C&I Capacity Reduction option (potential grows from less 1 MW in 2022 to around 5 MW in 2040). Large C&I is third highest at around 15% share, followed by small C&I at 13% and single-family low income at 9% share in total in 2040. Both regular multifamily and low income multifamily have almost equal contribution at less than 5%. EV does not appear for the Upper Peninsula, since EV Managed Charging was not cost-effective.

Figure 3-12. Upper Peninsula Electric Summer Achievable Potential by Customer Segment (MW at Meter)



Source: Guidehouse analysis

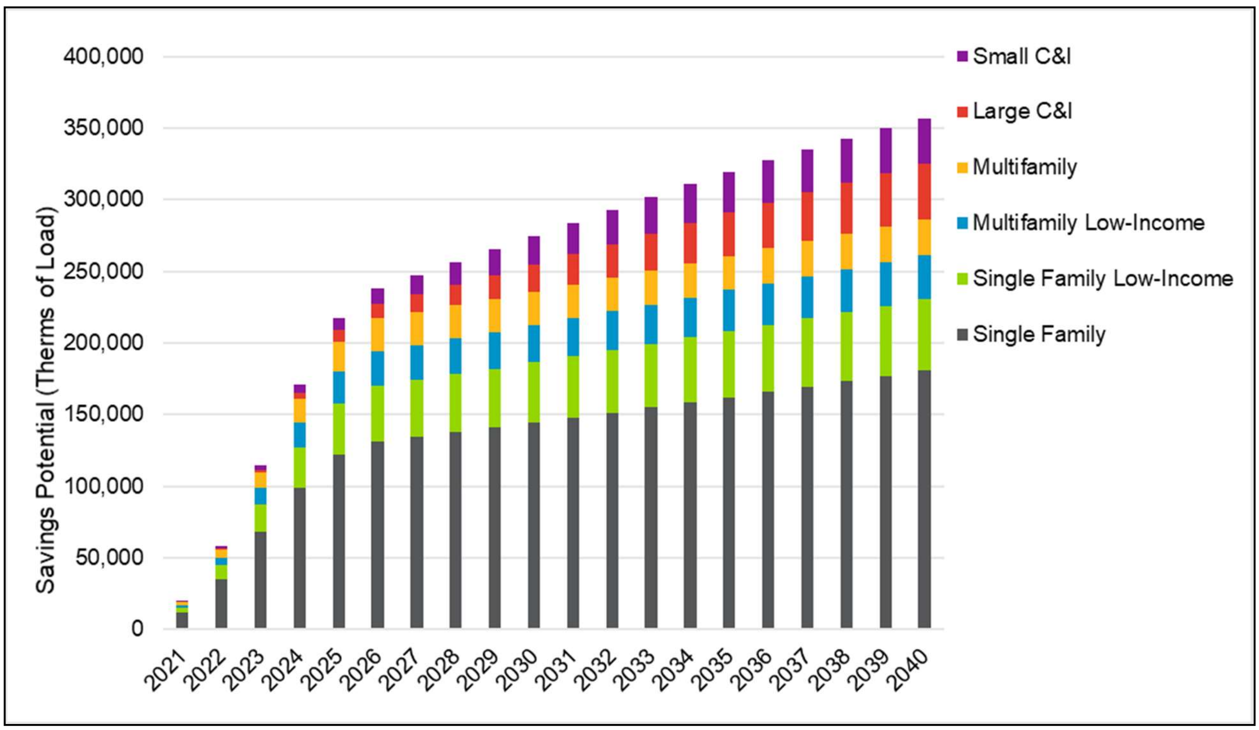
3.2.3.3 Lower Peninsula Natural Gas Winter Achievable Potential by Customer Segment

Figure 3-13 shows the natural gas winter achievable potential by customer segment for the Lower Peninsula. Residential customers (across all segments) have 80% or more share in the total potential, with the remaining 20% from small and large C&I customers.

Within residential, single-family contributes the most to total achievable potential, with 12,065 therms (61%) out of a total 19,638 therms in 2021, and continues as such over the study period, contributing 180,789 therms (51%) of total 356,560 therms in 2040. Single-family low income has approximately 15% share, followed by the multifamily segments (with less than 10% share from each). Majority of the residential potential is associated with the BYOT option, for which potential steadily increases with growth in adoption of smart thermostats from an integrated EWR-DR standpoint for customers (as discussed previously, customer payback decreases when customers factor in both EWR and DR benefits in their decision-making to purchase a smart thermostat, which in turn enhances customer adoption of the enabling technology). The second highest contribution from residential customers in natural gas DR is from Behavioral DR.

For C&I customers, the contribution from C&I Capacity Reduction-Gas (applies to large C&I) and from BYOT (applies to small C&I) is almost equal. Similar to electric, the growth in adoption of enabling technologies such as smart thermostats for small C&I and EMS for large C&I drives up potential from these segments (considered EWR and DR benefits in customer adoption of these technologies as previously discussed).

Figure 3-13. Lower Peninsula Natural Gas Winter Achievable Potential (therms) by Customer Segment, 2021-2040 (at Meter)

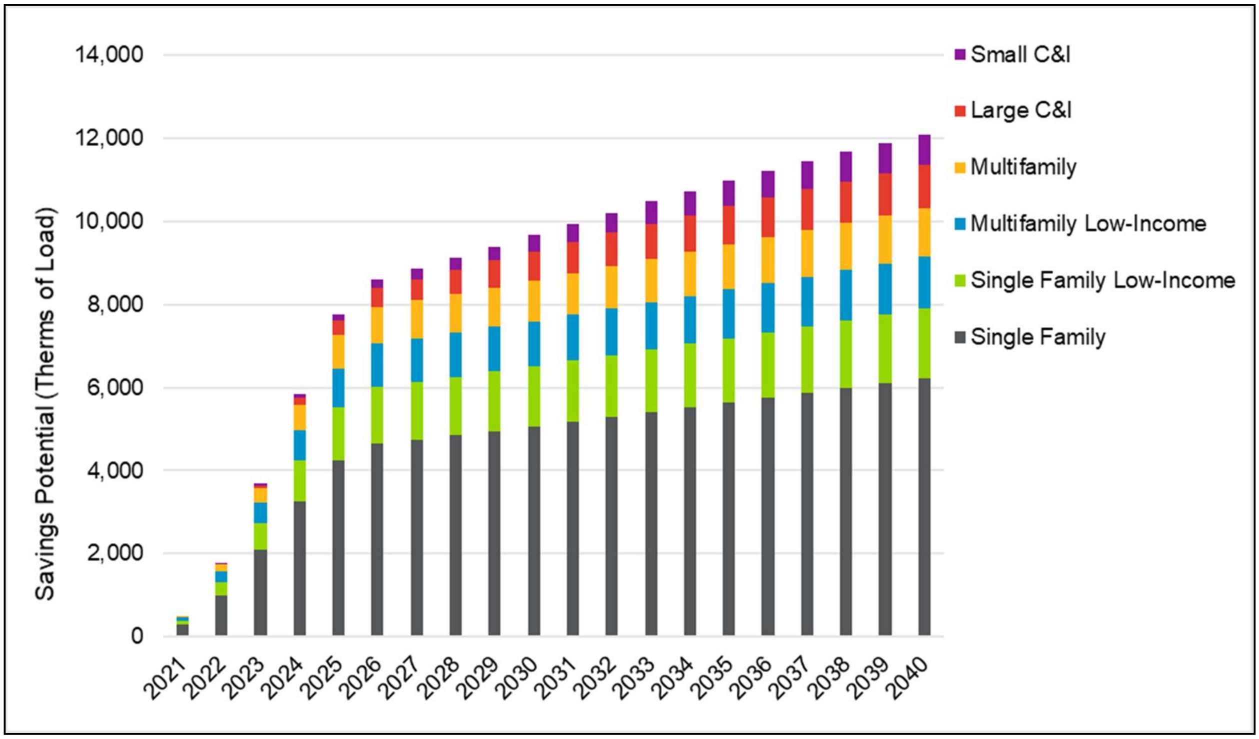


Source: Guidehouse analysis

3.2.3.4 Upper Peninsula Natural Gas Winter Achievable Potential by Customer Segment

Figure 3-14 shows the long-term natural gas winter achievable potential by customer segment for the Upper Peninsula. These results show similar trends as those for the Lower Peninsula. Single-family contributes the most to total achievable potential, with 293 therms (57%) out of a total 518 therms in 2021, and with 6,216 therms (51%) of total 12,085 therms in 2040. The shares from the other segments are similar to those discussed for the Lower Peninsula.

Figure 3-14. Upper Peninsula Natural Gas Winter Achievable Potential (therms) by Customer Segment, 2021-2040 (at Meter)



Source: Guidehouse analysis

3.2.4 Achievable Potential Results by Scenario

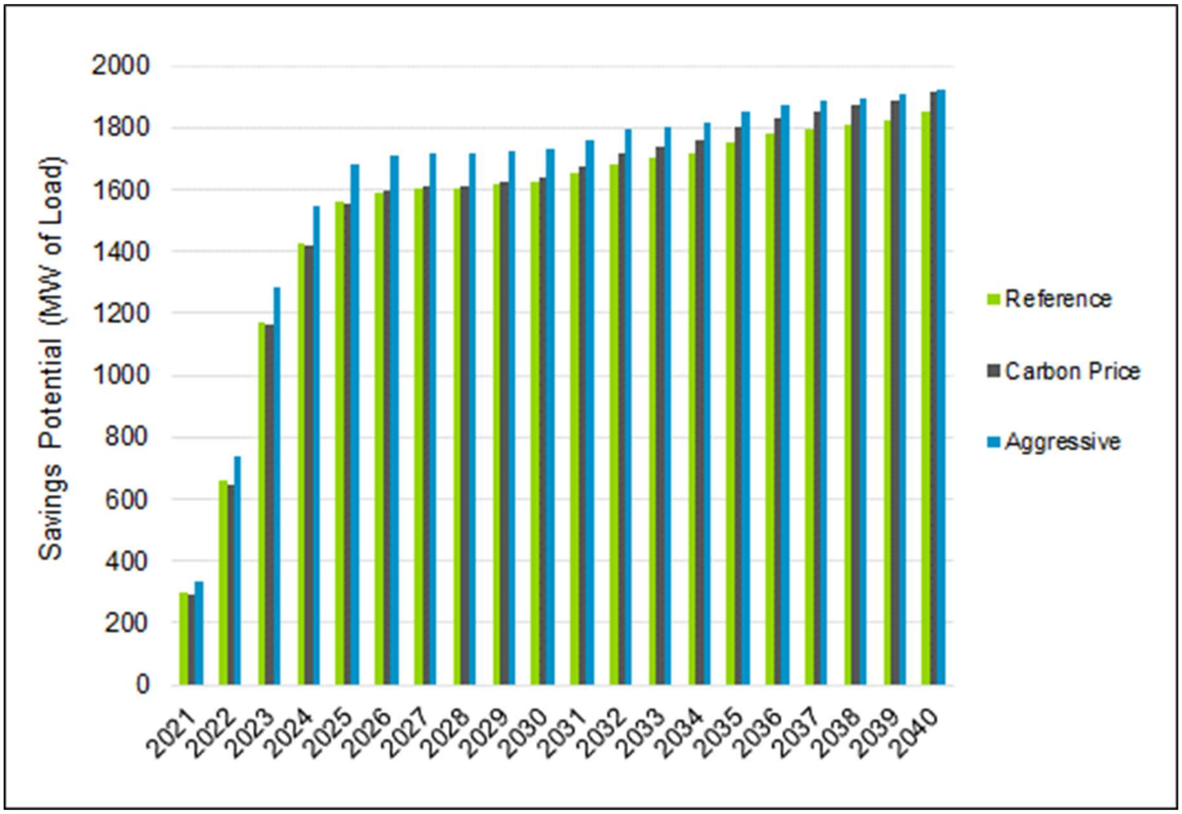
This section compares the potential results across the three scenarios considered in the study and described previously in Section 2.3.2. The scenarios discussed in this study are Reference, Aggressive, and Carbon Price. This section discusses electric summer peak reduction and natural gas DR potential results for the Lower and the Upper Peninsula. Information on winter electric achievable potential results can be found in the excel results dashboard (Appendix D).

3.2.4.1 Lower Peninsula Electric Summer Achievable Potential by Scenario

Figure 3-16 shows Lower Peninsula electric summer achievable potential by scenario in MWs and Figure 3-16 represents the potential as "% of peak demand". The Aggressive Scenario consistently has the highest potential due to the increased participation assumed in this scenario, despite the removal of the non-cost-effective measures. In the long-term, it has an average 5% higher potential than the Reference Case.

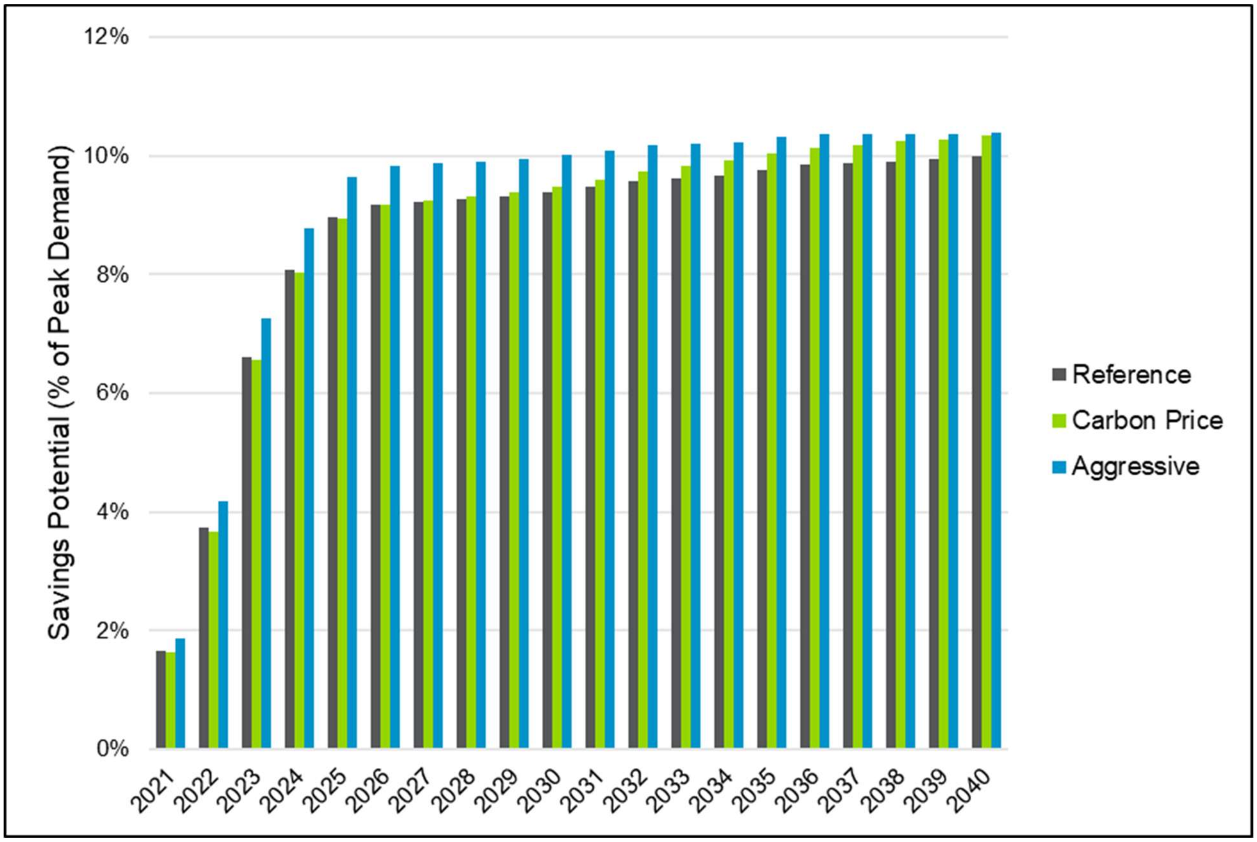
Potential in the Carbon Price Scenario grows to exceed the Reference Scenario in the later years due to the increased adoption of enabling technologies, namely smart thermostats, EVs, and batteries.

Figure 3-15. Lower Peninsula Electric Summer Achievable Potential by Scenario (MW at Meter)



Source: Guidehouse analysis

Figure 3-16. Lower Peninsula Electric Summer Achievable Potential by Scenario (% of Peak Demand)



Source: Guidehouse analysis

3.2.4.2 Upper Peninsula Electric Summer Achievable Potential by Scenario

Figure 3-17 shows the Upper Peninsula electric summer achievable potential by scenario in MWs and Figure 3-18 shows the same results as % of system peak. The trends discussed for the Lower Peninsula potential apply.

Figure 3-17. Upper Peninsula Electric Summer Achievable Potential by Scenario (MW at meter)

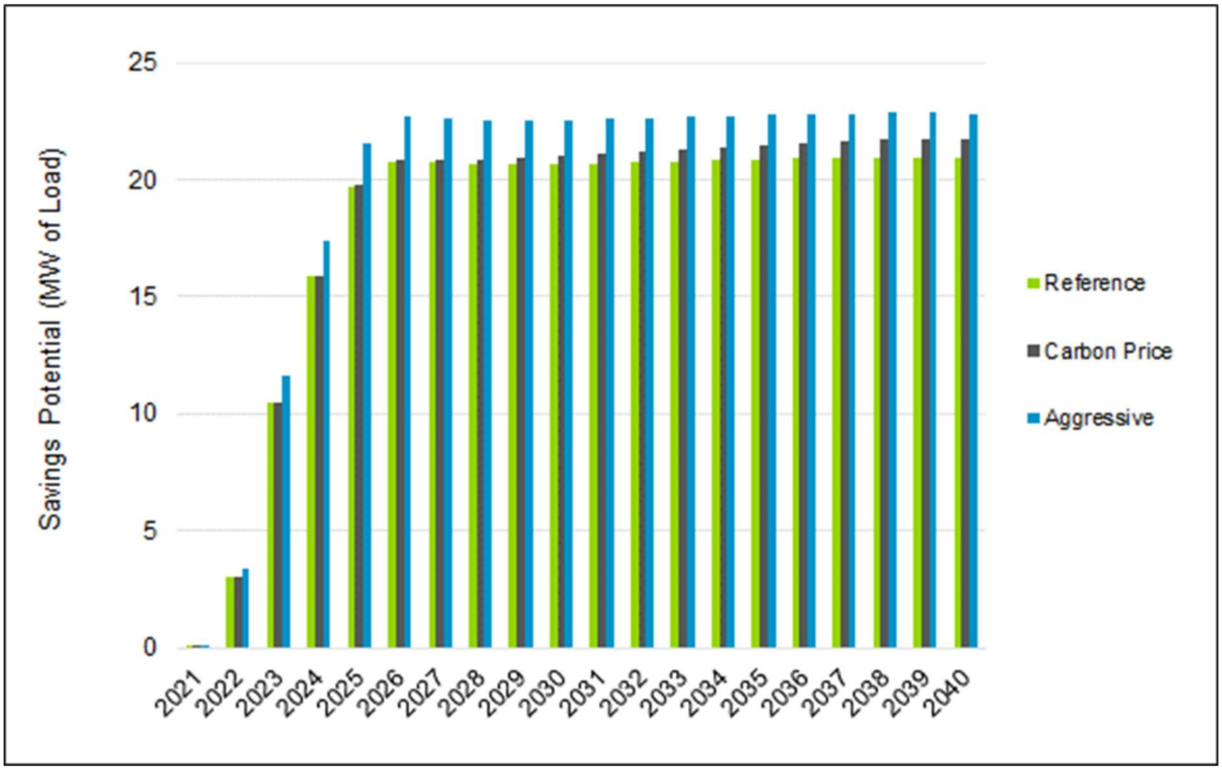
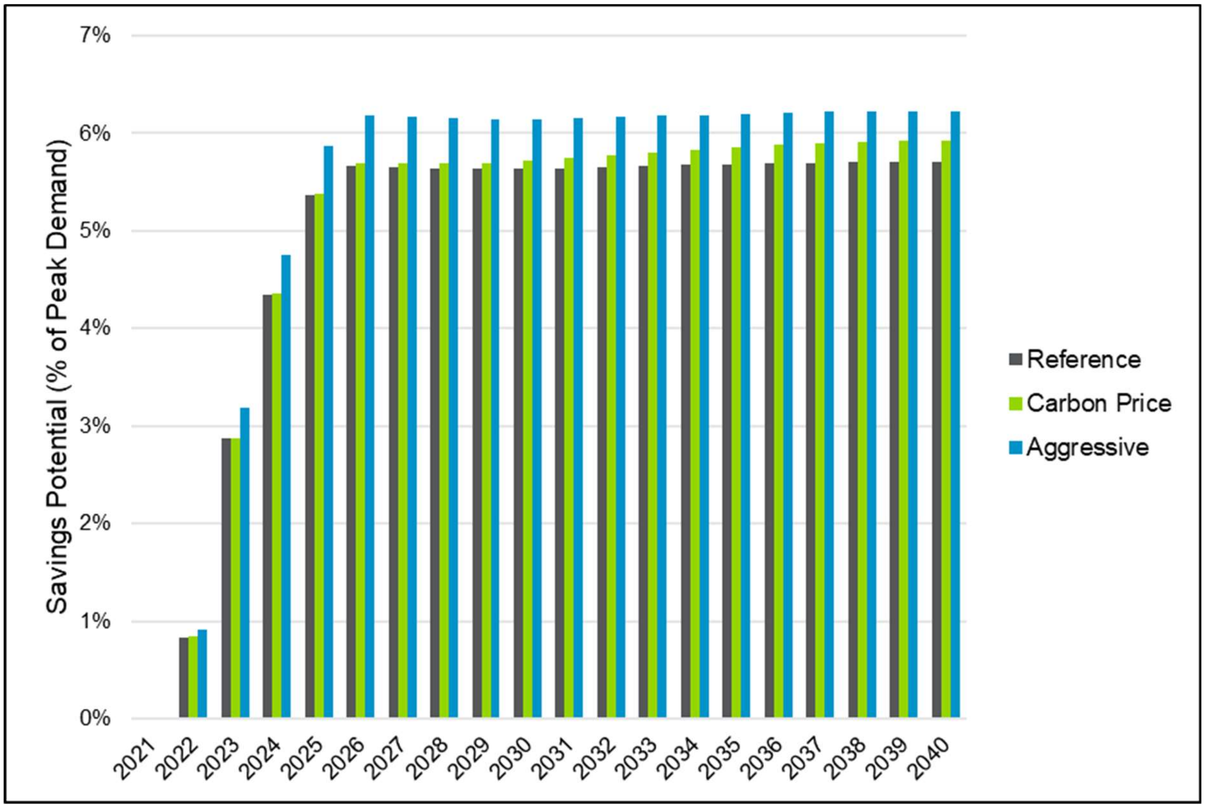


Figure 3-18. Upper Peninsula Electric Summer Achievable Potential by Scenario (% of peak demand)

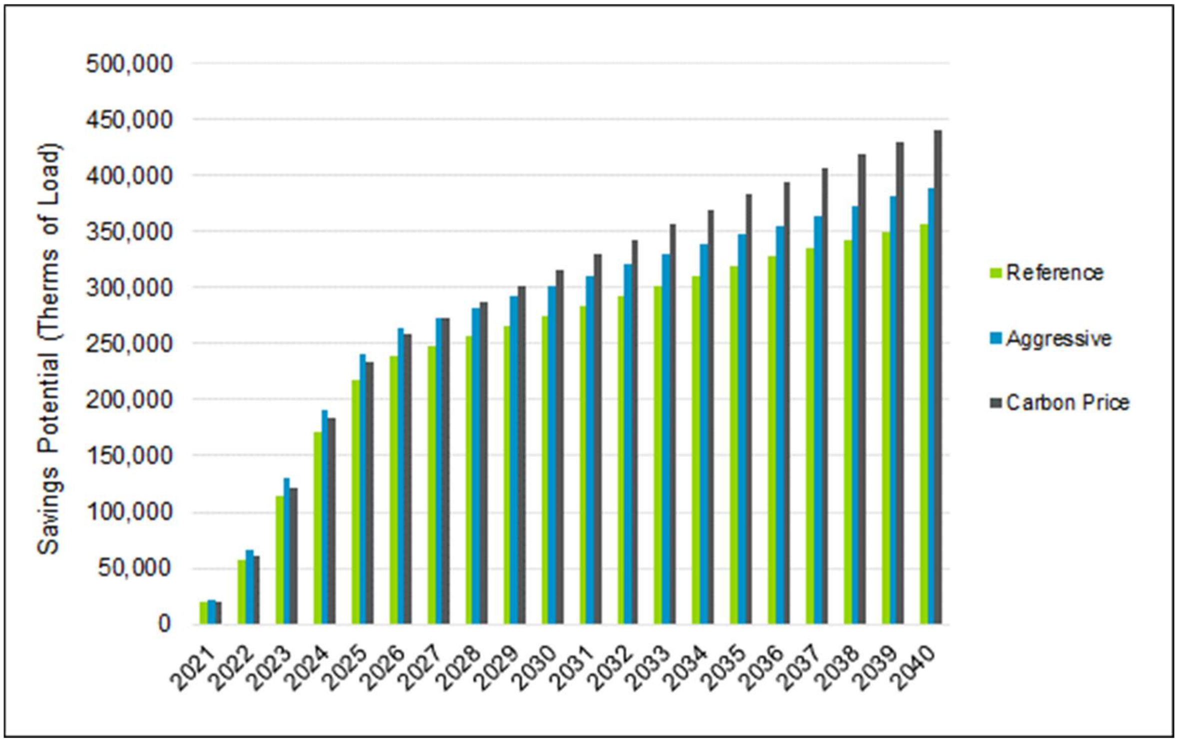


Source: Guidehouse analysis

3.2.4.3 Lower Peninsula Natural Gas Winter Achievable Potential by Scenario

Figure 3-19 shows the Lower Peninsula natural gas winter achievable potential by scenario. The Aggressive Scenario potential is around 10% higher than the Reference Scenario potential, driven by higher incentives and consequently higher participation levels in DR programs. The Carbon Price Scenario potential results are almost 20% higher than the Reference Scenario results. This increase in potential is primarily driven by higher potential from the BYOT program offer for gas, which in turn is due to greater adoption of smart thermostats in the Carbon Price Scenario than the Reference Scenario.

Figure 3-19. Lower Peninsula Natural Gas Winter Achievable Potential by Scenario (therms at Meter)

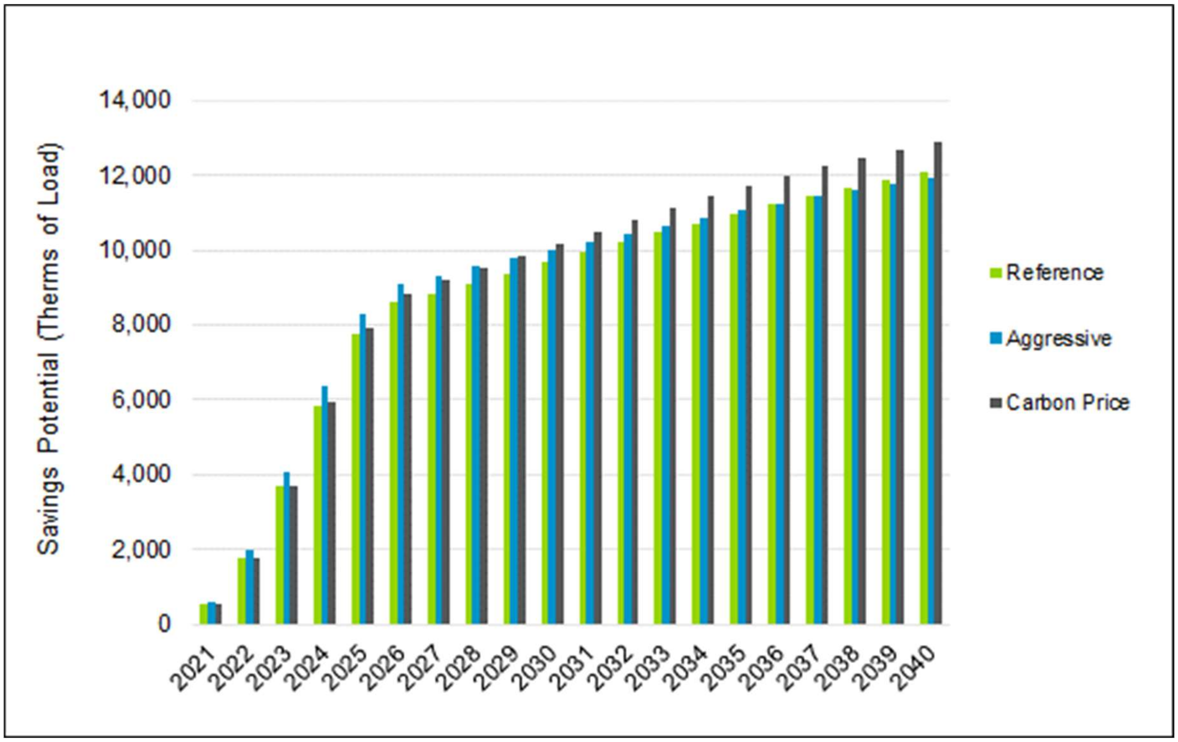


Source: Guidehouse analysis

3.2.4.4 Upper Peninsula Natural Gas Winter Achievable Potential by Scenario

Figure 3-20 shows the Upper Peninsula natural gas winter achievable potential by scenario. The increase in energy efficiency potential and differences in smart thermostat adoption in the Aggressive Scenario leads to slightly lower potential in the later years compared to the Reference Scenario. The higher potential in the Carbon Price Scenario than the Reference Scenario is primarily due to greater potential from the BYOT option for gas.

Figure 3-20. Upper Peninsula Natural Gas Winter Achievable Potential by Scenario (therms at Meter)



Source: Guidehouse analysis

3.3 Annual Program Costs

This section first presents the annual cost estimates of the total DR portfolio by scenario type and then by option. The annual costs shown represent the total costs for achieving both summer and winter peak reductions.

3.3.1 DR Portfolio Annual Costs

The figures in this section show the annual costs at the portfolio level by scenario. These costs represent the total annual costs estimated to incur to realize the potential values discussed above. The costs represent a sum of all different types of fixed and variable costs, either incurred one-time or on a recurring basis, for implementing the DR programs (refer to Section 2 for a description of the different types of costs).

The cyclical nature of the annual costs over the analysis timeframe is due to the fact that the costs grow in the initial years while the program is ramping up as the programs incur enabling technology costs (e.g., DLC-switch, CPP with enabling technology) and customer marketing and recruitment costs during the ramp up stage. Once the programs mature and the participation levels off, these one-time variable costs are no longer incurred and therefore the annual program costs level off. At that stage, the annual costs primarily consist of incentive payments to customers, O&M costs, and annual program administration costs. However, program development costs and technology enablement costs are reincurred at the end of the program life and technology life, respectively, and this trend leads to the increased costs during the 2030-2032 timeframe, and the 2040 timeframe.

Costs are higher for the Carbon Price Scenario and Aggressive Scenario compared to the Reference Scenario costs due to higher incentives paid to customers, additional marketing and outreach, higher technology enablement costs and higher O&M costs incurred because of higher customer enrollment in these scenarios.

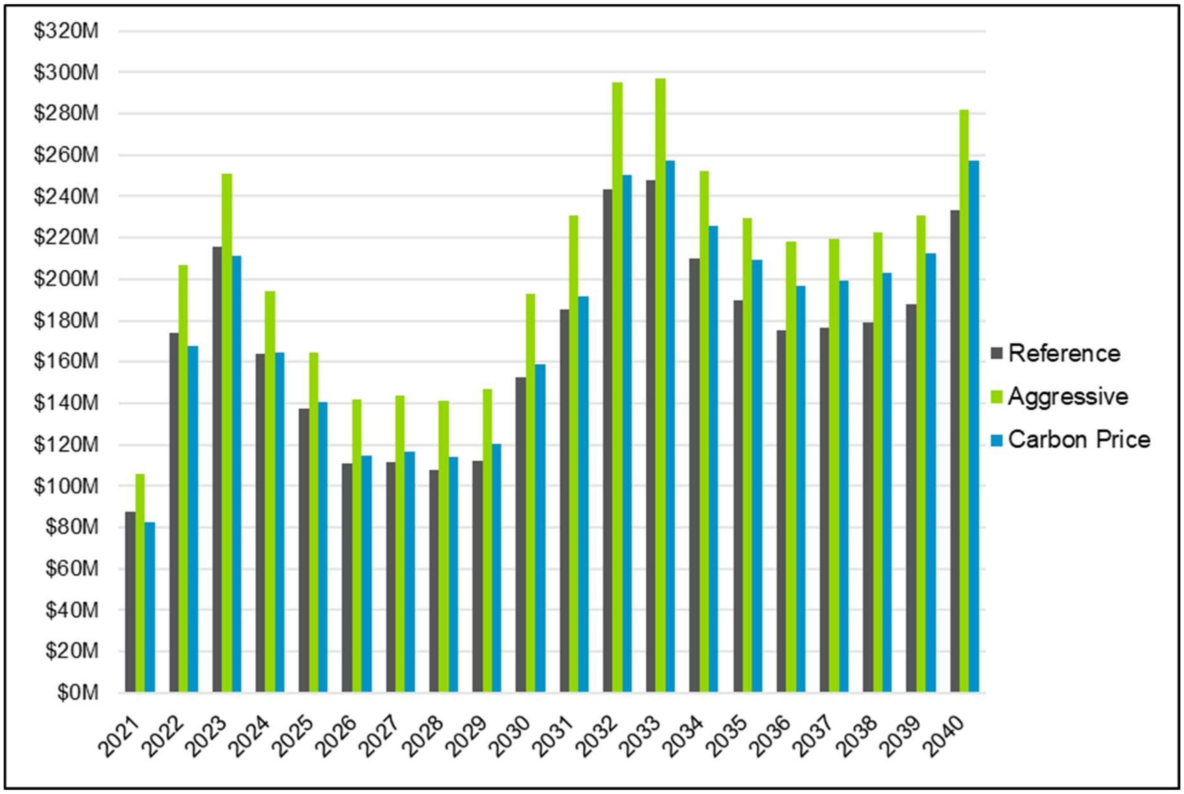
The DR program total portfolio costs exhibit the following growth trends:

- Based on long-term cost-effectiveness screening, the annual portfolio costs across both regions are expected to grow:
    - From $85 million in 2021 to $188 million in 2040 for the Reference Scenario
    - From $101 million in 2021 to $210 million in 2040 for the Aggressive Scenario
    - From $96 million in 2021 to $413 million in 2040 for the Carbon Price Scenario

3.3.1.1 Lower Peninsula Electric Annual DR Portfolio Costs by Scenario

Figure 3-21 shows the Lower Peninsula electric annual DR portfolio costs by scenario. The Lower Peninsula contributes over 99% of the statewide costs. Initially, the Carbon Price Scenario has slightly lower costs compared to the Reference Scenario due to the effects of greater energy efficiency reductions on the baseline peak and thus the demand impacts; however, this effect is quickly overshadowed by the increased costs associated with more aggressive battery and EV adoption assumptions for the Carbon Price Scenario. Over the study period, the Aggressive Scenario has the highest costs due to the increased incentives and more aggressive assumptions of enabling technology adoption.

Figure 3-21. Lower Peninsula Electric Annual DR Portfolio Costs by Scenario

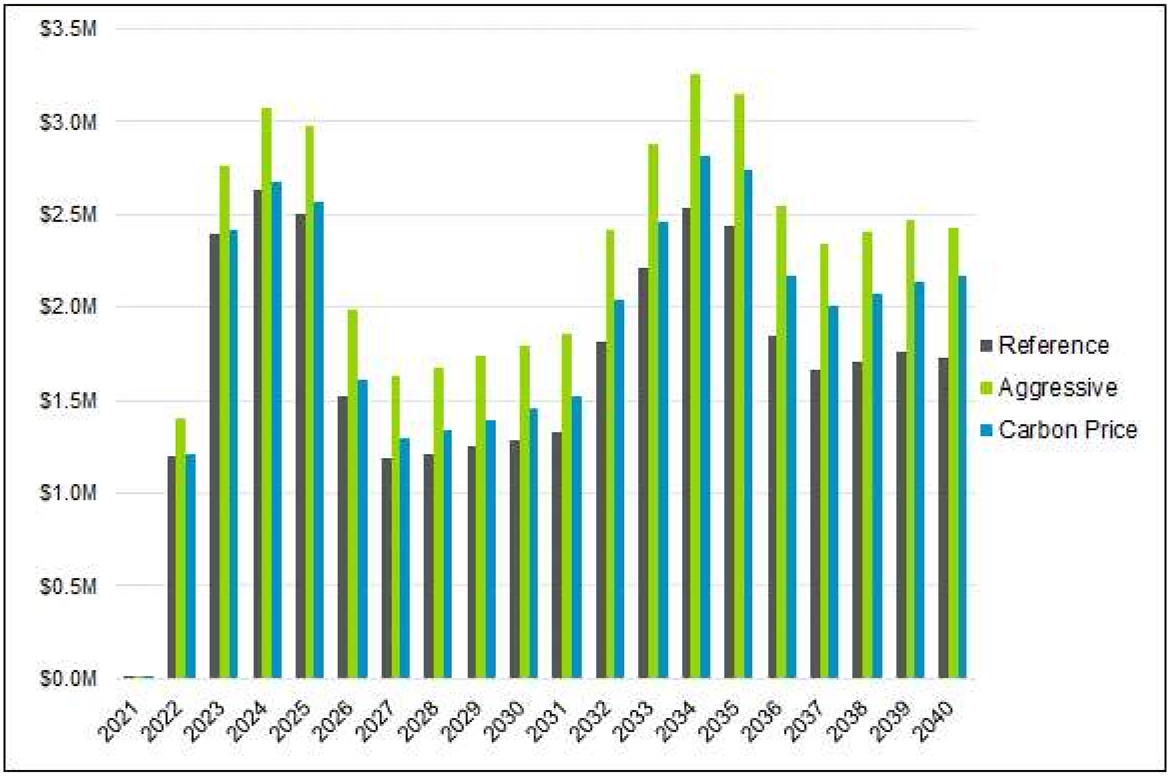


Source: Guidehouse analysis

3.3.1.2 Upper Peninsula Electric Annual DR Portfolio Costs by Scenario

Figure 3-22 shows the Upper Peninsula electric annual DR portfolio costs by scenario. The trends in the Upper Peninsula are similar to those in the Lower Peninsula.

Figure 3-22. Upper Peninsula Electric Annual DR Portfolio Costs by Scenario

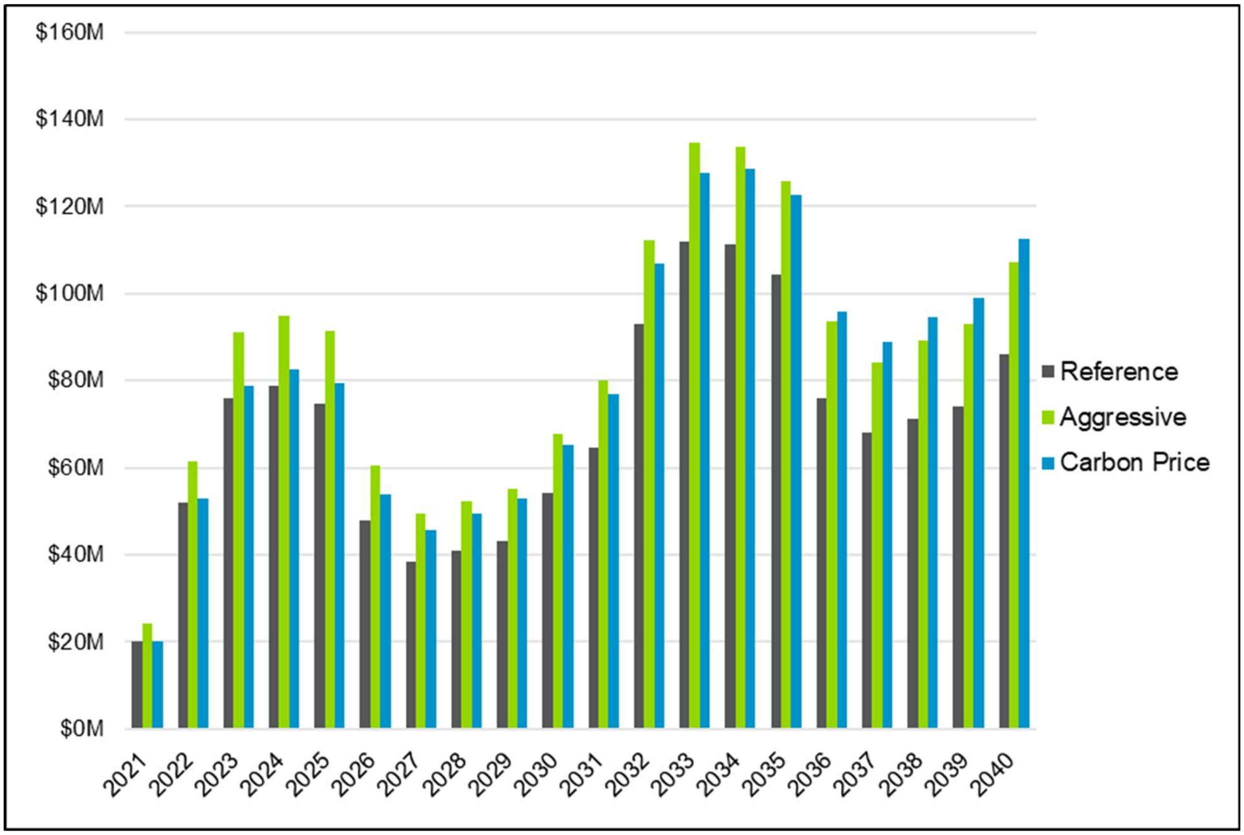


Source: Guidehouse analysis

3.3.1.3 Lower Peninsula Natural Gas Annual DR Portfolio Costs by Scenario

Figure 3-23 shows the Upper Peninsula natural gas annual DR portfolio costs by scenario. The Aggressive Scenario has the highest costs for the first 15 years due to the increased incentives in this scenario. The Carbon Price Scenario consistently has higher costs compared to the Reference Scenario and has the highest costs of all scenarios during the last few years of the study; this is primarily driven by the increased adoption of smart thermostats eligible for BYOT, which leads to a growth in the program.

Figure 3-23. Lower Peninsula Gas Annual DR Portfolio Costs by Scenario

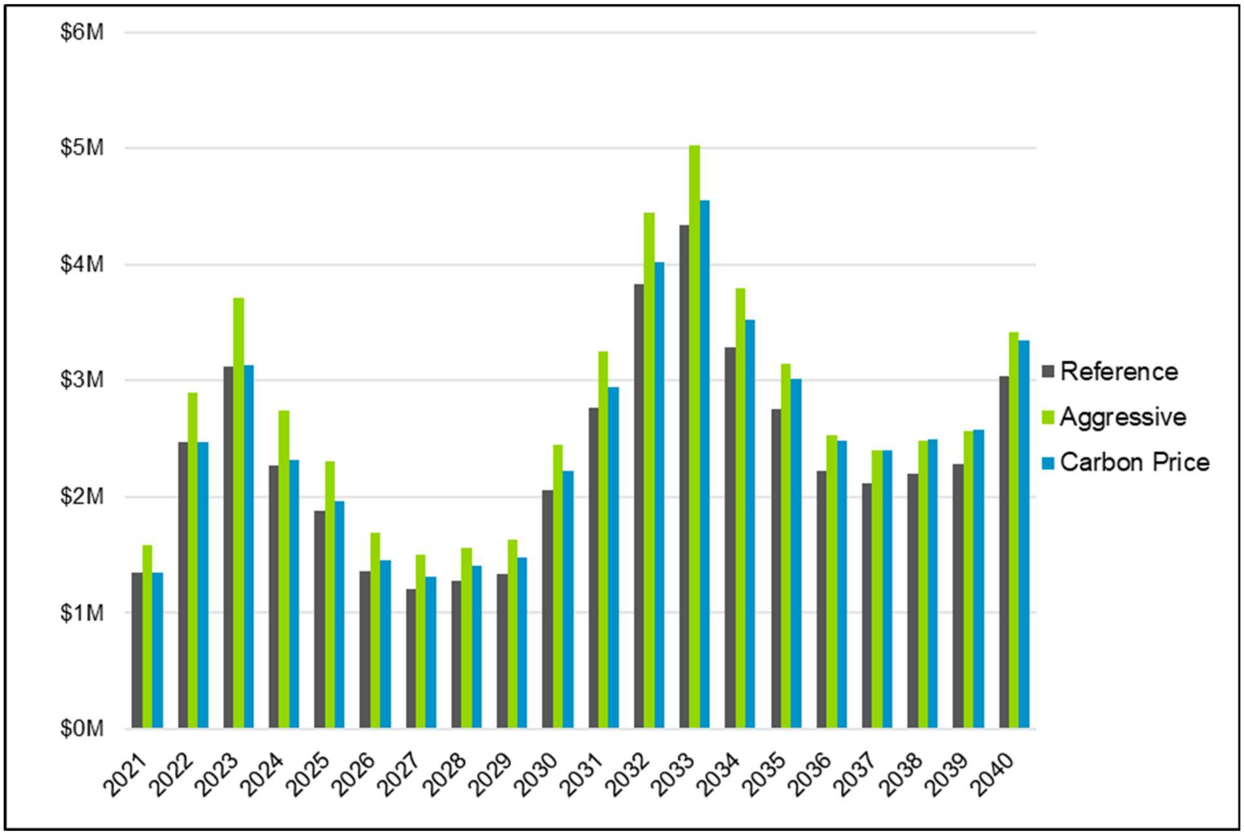


Source: Guidehouse analysis

3.3.1.4 Upper Peninsula Natural Gas Annual DR Portfolio Costs by Scenario

Figure 3-24 shows the Upper Peninsula natural gas annual DR portfolio costs by scenario. The Aggressive Scenario generally has the highest costs due to the increased incentives in this scenario.

Figure 3-24. Upper Peninsula Natural Gas Annual DR Portfolio Costs by Scenario



Source: Guidehouse analysis

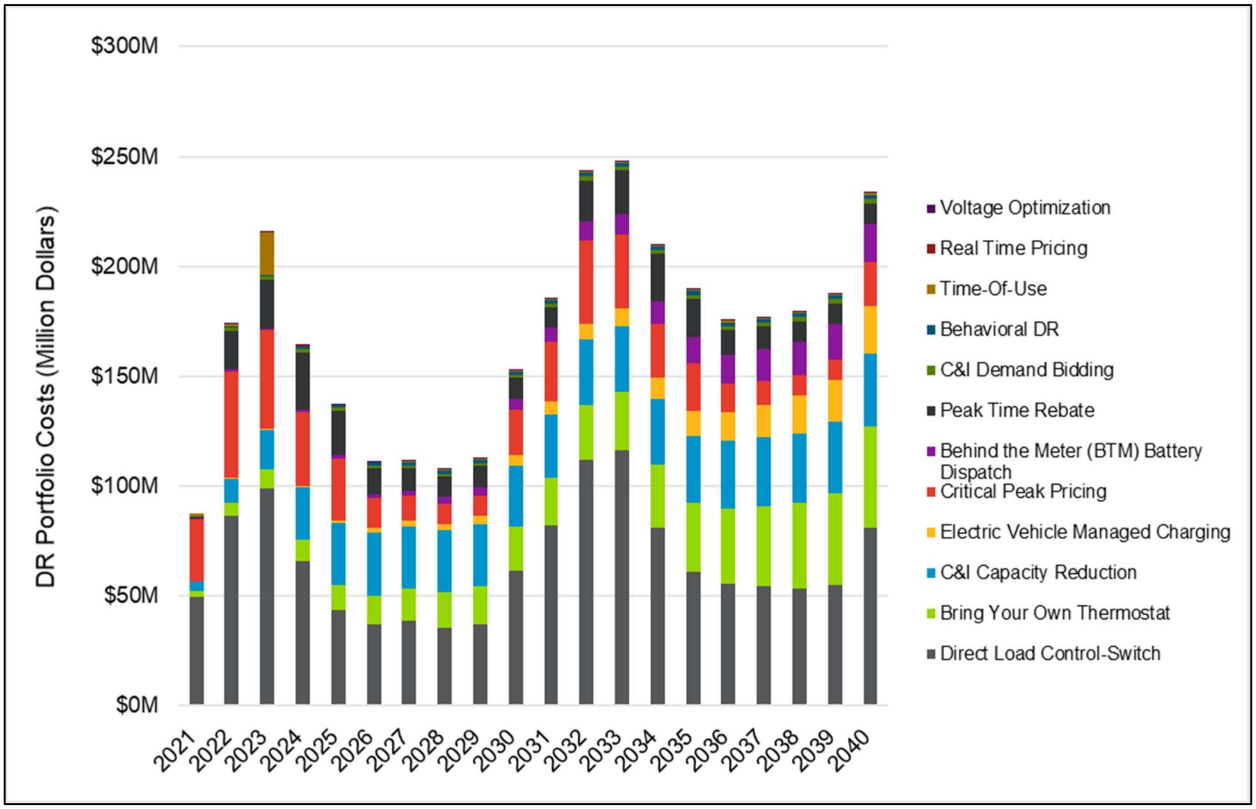
3.3.2 Annual Costs by DR Option

This section shows the annual costs for cost-effective electric DR options and all natural gas DR options for the Reference Scenario. This section shows the annual costs for cost-effective electric DR options and all natural gas DR options for the Reference Scenario. The major cost components are customer incentives, marketing and outreach costs, and technology enablement costs. The proportion of costs in the Aggressive Scenario and Carbon Price Scenario follow a similar trend.

3.3.2.1 Lower Peninsula Electric Annual DR Portfolio Costs by Option

Figure 3-25 shows the Lower Peninsula electric annual DR portfolio costs by cost-effective DR option. In 2040, the portfolio cost is $233 million, with the DLC-switch options (34%) and BYOT options (20%) contributing the most, followed by C&I Capacity Reduction (17%). EV Managed Charging and BTM Battery Dispatch each have approximately 10% share in total costs. The remaining DR options individually have 5% or less share in total costs. The swings in costs for DLC-Switch and CPP are due to enabling technology costs, which are assumed to have a 10-year lifetime and therefore these enabling technology costs are reincurred at the end of the technology lifetime.

Figure 3-25. Reference Scenario Lower Peninsula Electric Annual DR Portfolio Costs by Option

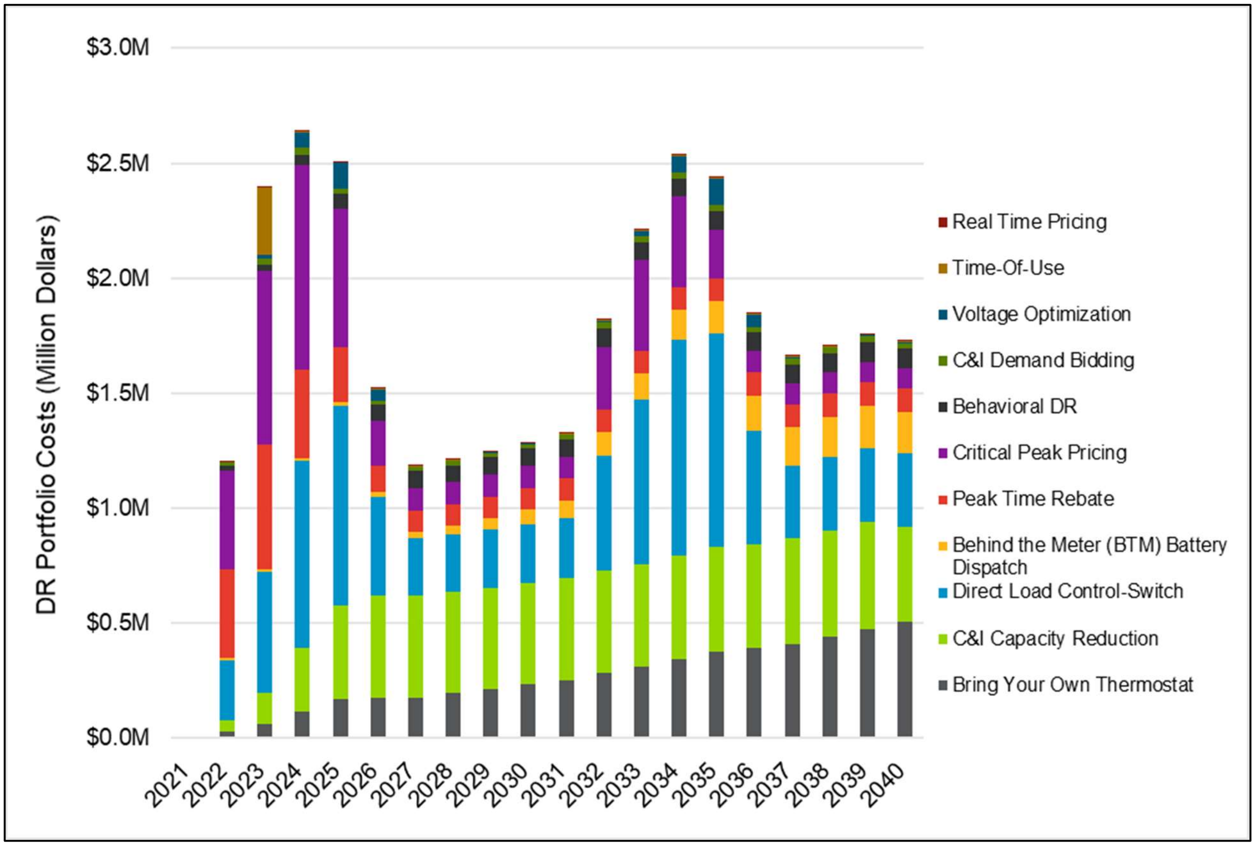


Source: Guidehouse analysis

3.3.2.2 Upper Peninsula Electric Annual DR Portfolio Costs by Option

Figure 3-26 shows the Upper Peninsula electric annual DR portfolio costs by cost-effective DR option. In 2040, the portfolio cost is $1.7 million, with the DLC-switch options (30%) and BYOT options (24%) contributing the most. The explanation of the cost trends and the cyclical nature of the costs are the same as those discussed previously for the Lower Peninsula.

Figure 3-26. Reference Scenario Upper Peninsula Electric Annual DR Portfolio Costs by Option

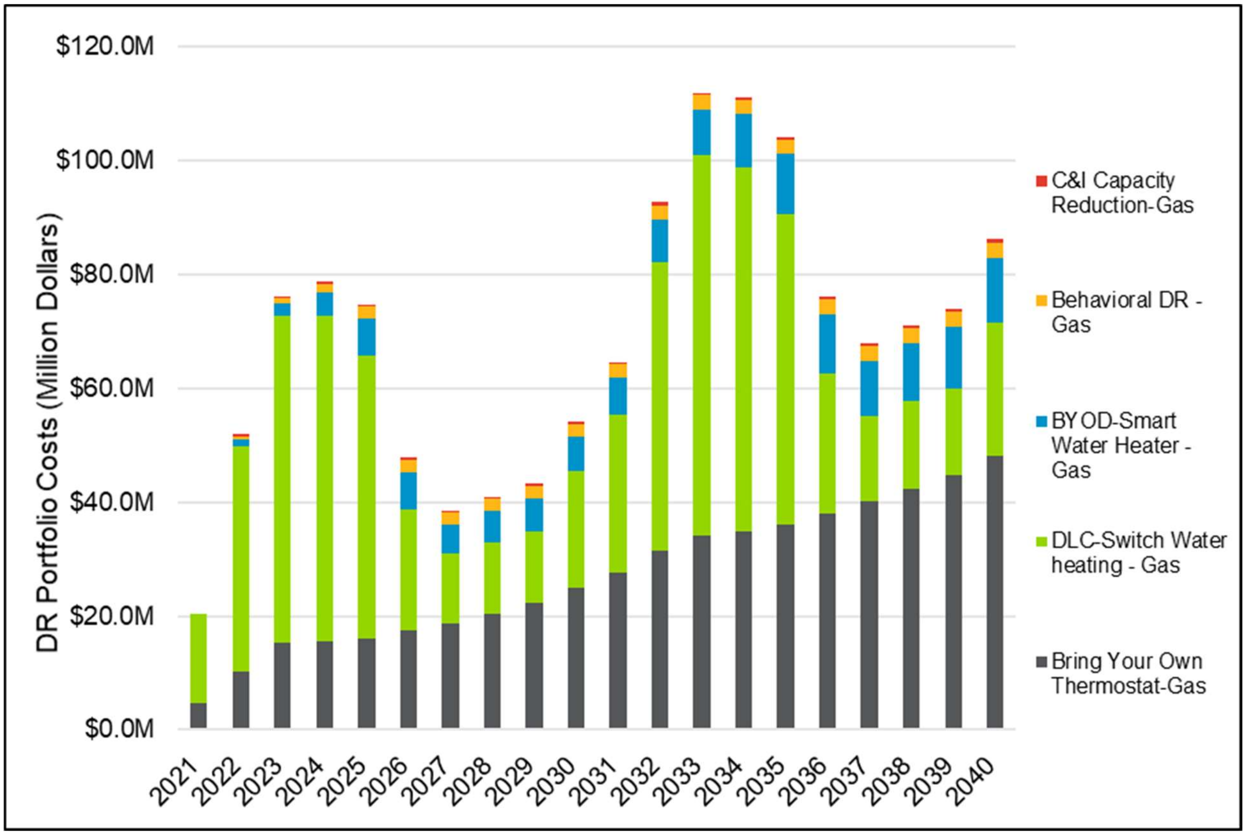


Source: Guidehouse analysis

3.3.2.3 Lower Peninsula Natural Gas Annual DR Portfolio Costs by Option

Figure 3-27 shows the Lower Peninsula natural gas annual DR portfolio costs for all DR options. In 2040, the portfolio cost is $86 million, with BYOT (56%) and DLC-switch water heating (27%) contributing the most. The cyclical nature of the costs for DLC-switch is due to the same reasons explained previously under electric, where the switch costs are reincurred at the end of the technology lifetime.

Figure 3-27. Reference Scenario Lower Peninsula Natural Gas Annual DR Portfolio Costs by Option

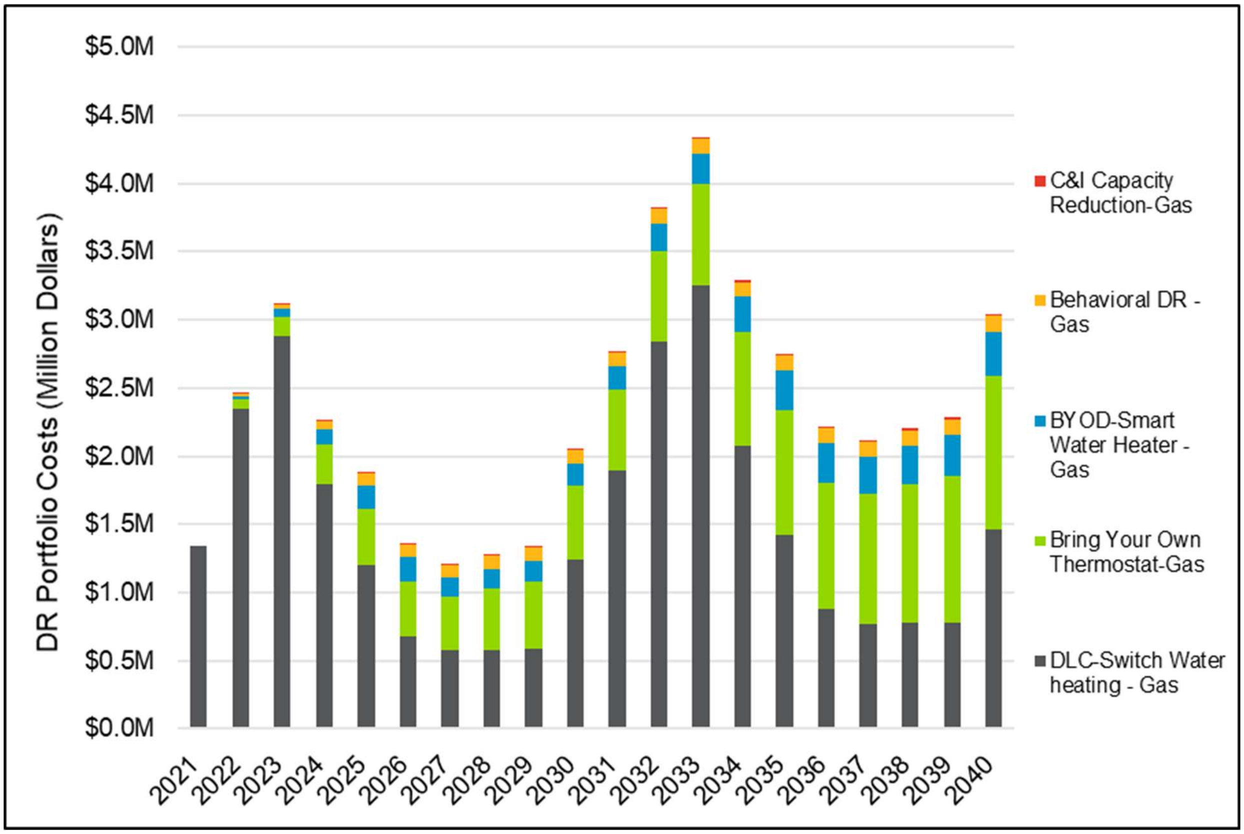


Source: Guidehouse analysis

3.3.2.4 Upper Peninsula Natural Gas Annual DR Portfolio Residential Costs by Option

Figure 3-28 shows the Upper Peninsula natural gas annual DR portfolio costs for all DR options. In 2040, the portfolio cost is $3 million, with BYOT (48%) and DLC-switch water heating (37%) contributing the most.

Figure 3-28. Reference Scenario Upper Peninsula Natural Gas Annual DR Portfolio Residential Costs by Option



Source: Guidehouse analysis

4. Conclusions

The DR potential study results presented in this report assess both summer and winter peak electric demand reduction potential, and winter natural gas DR potential. The study incorporated the latest market data on customer characteristics and DR program performance from the Michigan utilities, and primary research (customer surveys) conducted to assess customer awareness of and willingness to enroll in different DR program types. The residential and C&I customer surveys provided valuable information to help inform the likelihood of customers participating in different DR program types. The DR study considered interactions resulting from the EWR study and incorporated baseline adjustments from the EWR analysis to project baseline peak demand, net of EWR savings, for assessing DR potential. In addition to the baseline adjustments, the study incorporated EWR-DR integration in modeling customer adoption of technologies that provide EWR and DR co-benefits (e.g., smart thermostats), which provide useful insights on EWR and DR value stacking for the customer. Following are the key findings and takeaways from the DR potential analysis:

- **Electric DR Achievable Potential Trends:** The statewide electric DR achievable potential is expected to grow substantially over the 2021-2040 timeframe. The summer peak electric demand reduction for the Lower Peninsula is expected to grow to about 10% of summer peak in the long-term, from 2% to 3% in the initial years (projected to grow from around 300 MW to 1,850 MW over the 20-year timeframe). The Upper Peninsula long-term summer electric DR achievable potential is projected to achieve around 6% reduction in peak demand (projected to grow from around 3 MW to 20 MW over the 20-year timeframe). The top four DR options that constitute over 80% of the total cost-effective potential are – C&I Capacity Reduction, Bring Your Own Thermostat (BYOT) program, Critical Peak Pricing (CPP), and Direct Load Control-Switch. Advanced DR options, such as EV Managed Charging and BTM Battery Dispatch, grow steadily over time as adoption of these technologies increases.

- **Natural Gas DR Achievable Potential Trends:** The statewide natural gas DR achievable potential too is expected to grow substantially over the 20-year study timeframe. The total natural gas DR achievable potential for the Lower Peninsula is projected to grow from around 20,000 therms to more than 350,000 therms over the 20-year timeframe. The Upper Peninsula natural gas achievable potential is projected to grow from less than 2,000 therms to around 12,000 therms over the 20-year timeframe. More than 50% of the total savings are derived from the BYOT program option. Behavioral DR for residential and the C&I Capacity Reduction option for natural gas are the other major contributors toward natural gas potential.

- **EWR-DR Integration Benefits:** The study findings highlight the benefits of EWR-DR integration when considering customer adoption of technologies that provide EWR and DR benefits from a joint perspective. Integration of EWR and DR incentives in customer adoption leads to a significant increase in the potential from technologies that provide EWR and DR co-benefits. This is clearly illustrated through the enhanced adoption of technologies such as smart thermostats and Energy Management Systems (EMS) through the lowering of the customer payback period that leads to enhanced adoption when EWR and DR incentives are combined in customer decision-making to adopt these technologies. This result emphasizes the importance of EWR and DR value stacking in presenting integrated demand-side management (IDSM) program offerings to customers.

- **Customer Segment Contribution in Total Achievable Potential:** Residential customers in aggregate across all segments have more than a 60% share of the electric DR achievable potential for the Lower Peninsula, with the highest contribution from non-low income single-family customers. Out of the remaining 40% from the C&I sector, extra-large C&I customers have the highest contribution. Upper Peninsula electric DR achievable potential has an approximately equal contribution from residential and C&I customers, with single-family residential customers and extra-large C&I customers having highest share in achievable potential. For natural gas, more than 80% of the total DR achievable potential is derived from residential customers.

- **Bring Your Own Thermostat (BYOT) Potential Trends:** BYOT potential is projected to increase steadily with growth in adoption of smart thermostats. The adoption of smart thermostats is considered from an integrated EWR-DR standpoint where a customer factors in both EWR rebates and DR incentives in decision making to purchase a smart thermostat, which leads to a lowering of payback period (as compared to EWR rebate consideration only) and leads to greater adoption of the technology. BYOT potential significantly increases over time for both electric and natural gas for residential customers primarily, although it applies to small and medium C&I customers as well (growth in BYOT potential is shown in the C&I potential results too).

- **C&I Potential Trends:** The contribution from C&I customers is primarily from the C&I Capacity Reduction program which is currently offered by Michigan utilities and is widely offered by many other utilities. A substantial portion of this could potentially be derived from extra-large C&I customers where the controlled end-use depends on the facility type. The upward trend in C&I DR potential is also associated with increased adoption of technologies that provide dual EWR and DR benefits to the customers such as EMS and advanced lighting controls. Similar to smart thermostats, consideration of both EWR and DR incentives in customer decision-making to purchase these technologies leads to a lowering of the payback period, and thereby increased adoption of these technologies.

- **Cost-effectiveness of DR Options:** A majority of the DR options considered in the analysis are cost-effective under the avoided cost assumptions provided by the Michigan utilities. Among the top potential contributors, C&I Capacity Reduction and Critical Peak Pricing are highly cost-effective with UCT benefit-cost ratios of greater than 3.0. BYOT has significant contribution toward potential but has higher costs than C&I Capacity Reduction and CPP. The DLC-switch option has higher costs than BYOT due to enabling technology costs. It passes cost-effectiveness screening with a 0.8 UCT threshold for the Lower Peninsula but is not cost-effective for the Upper Peninsula. Advanced DR options such as BTM Battery Dispatch are cost-effective for both regions. However, EV Managed Charging passes cost-effectiveness for the Lower Peninsula but not for the Upper Peninsula

- **Scenario Results:** The Aggressive Scenario Results show higher achievable potential than the Reference Scenario due to higher incentive assumptions, and consequently higher participation in DR programs, even though a few DR options are no longer cost-effective under the Aggressive Scenario due to higher costs. The DR analysis Aggressive Scenario incorporates higher adoption of technologies that provide EWR and DR benefits from the EWR analysis, which is also reflected in the Aggressive Scenario results. The Carbon Price Scenario projects slightly greater DR achievable potential than the Reference Scenario, due to higher battery and EV projected participation. Additionally, greater adoption of EWR-DR technologies such as smart thermostats in the Carbon Price Scenario than the Reference Scenario leads to higher achievable potential associated with those technologies.

Appendix A. Residential Survey Instrument

MI Potential Study
Residential Survey_FII

Appendix B. Commercial & Industrial Survey Instrument

MI Potential Study Commercial Survey_F

Appendix C. Demand Response Technical Potential

Technical potential refers to the theoretical maximum potential under 100% participation of the eligible load. Guidehouse calculated technical potential by multiplying the eligible load or eligible customers by the unit impact for each suboption.

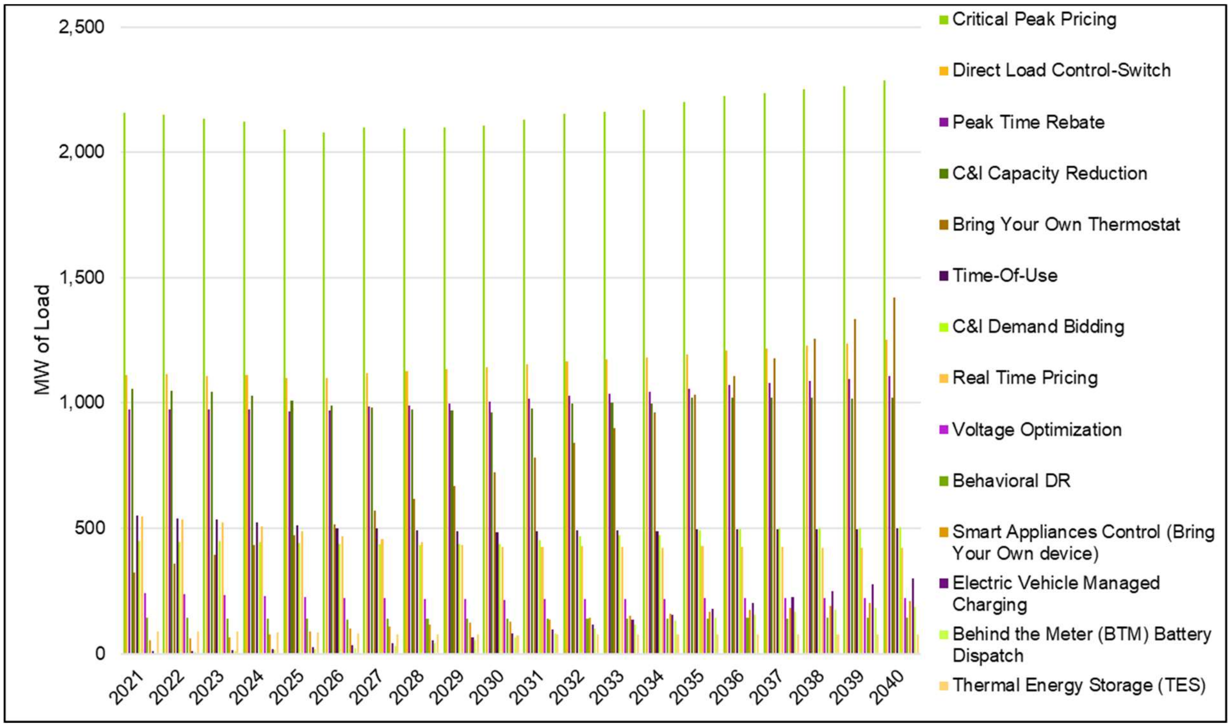
An important caveat is that, by definition, a technical potential calculation does not consider participation overlaps. Technical potential across the various suboptions are not additive and should not be added together to obtain a total technical potential. Therefore, the technical potential estimates for each DR suboption should be considered independently. The technical potential calculation is summarized through Equation C-1.

Equation C-1. DR Technical Potential

$$\begin{aligned} &Technical\ Potential_{DR\ Sub\ Option, End\ Use, Year} \\ &\quad = Eligible\ Load_{DR\ Sub\ Option, Segment, End\ Use, Year} \\ &\quad * Unit\ Impact_{DR\ Sub\ Option, Segment, Year} \end{aligned}$$

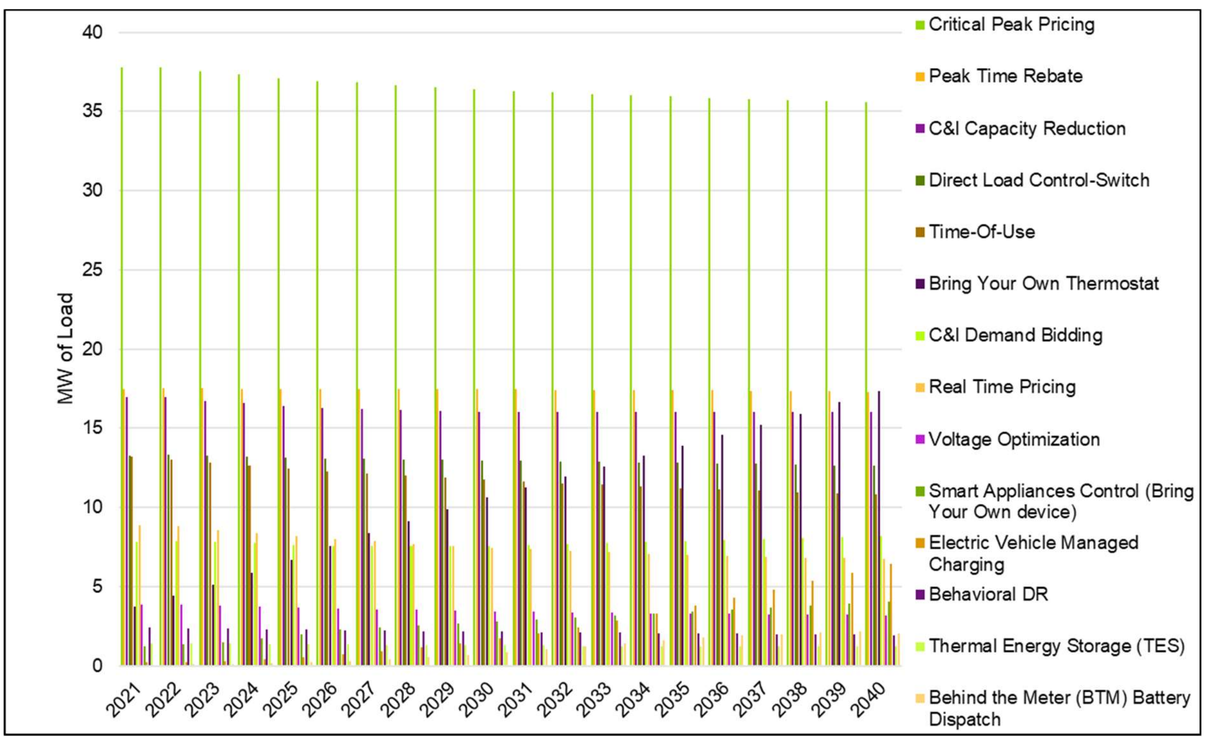
The following figures show electric technical potential results for each region and peak period by DR option. Savings for each customer segment can be viewed in the Technical Pot_Option tab in the DR Results dashboard (see Appendix D). Two general trends for technical potential savings over time depend on the customer segment and DR option. For DR impacts based on the percentage of load reduced, the savings trends will track the baseline peak forecast; for DR impacts based on kW reduction per unit, the savings trends track the account forecast projections. The technical potential for BTM battery, EV, and other DR options dependent on enabling technologies (e.g., BYOT, C&I capacity reduction – Auto-DR, C&I capacity bidding – Auto-DR) also track the increased adoption of these technologies.

Figure C-1. Technical Potential (MW) by Scenario for Lower Peninsula (Summer) from 2021-2040



Source: Guidehouse analysis

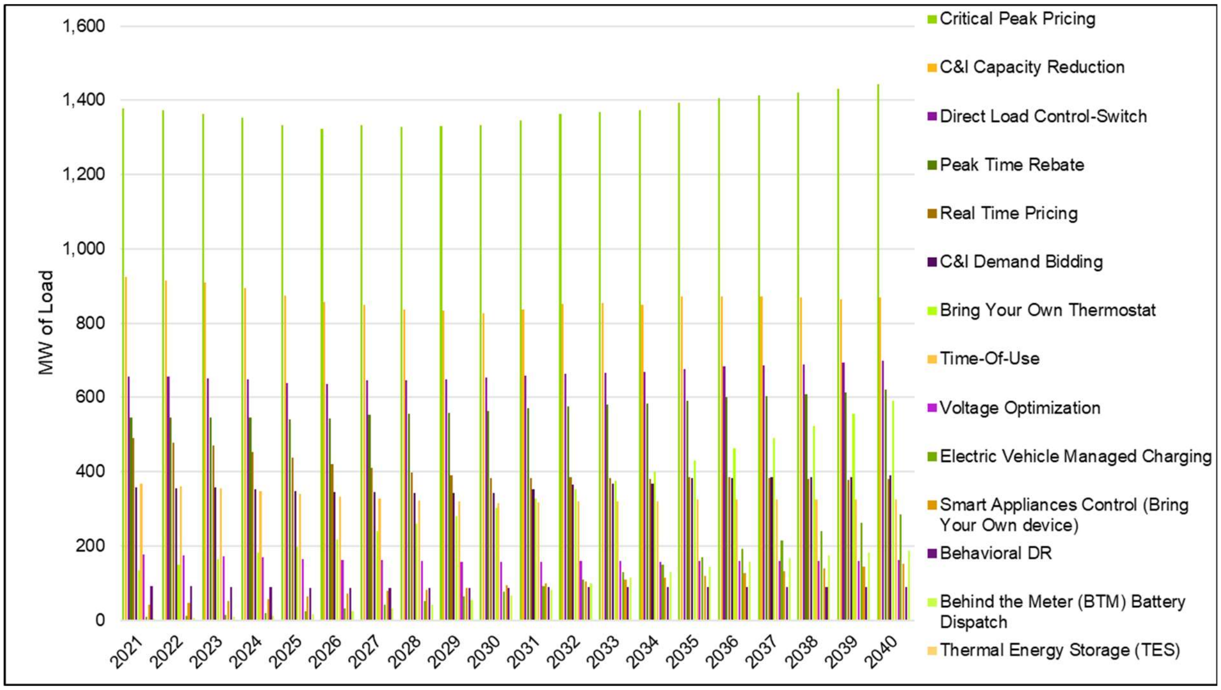
Figure C-2. Technical Potential (MW) by Scenario for Upper Peninsula (Summer) from 2021-2040



Source: Guidehouse analysis

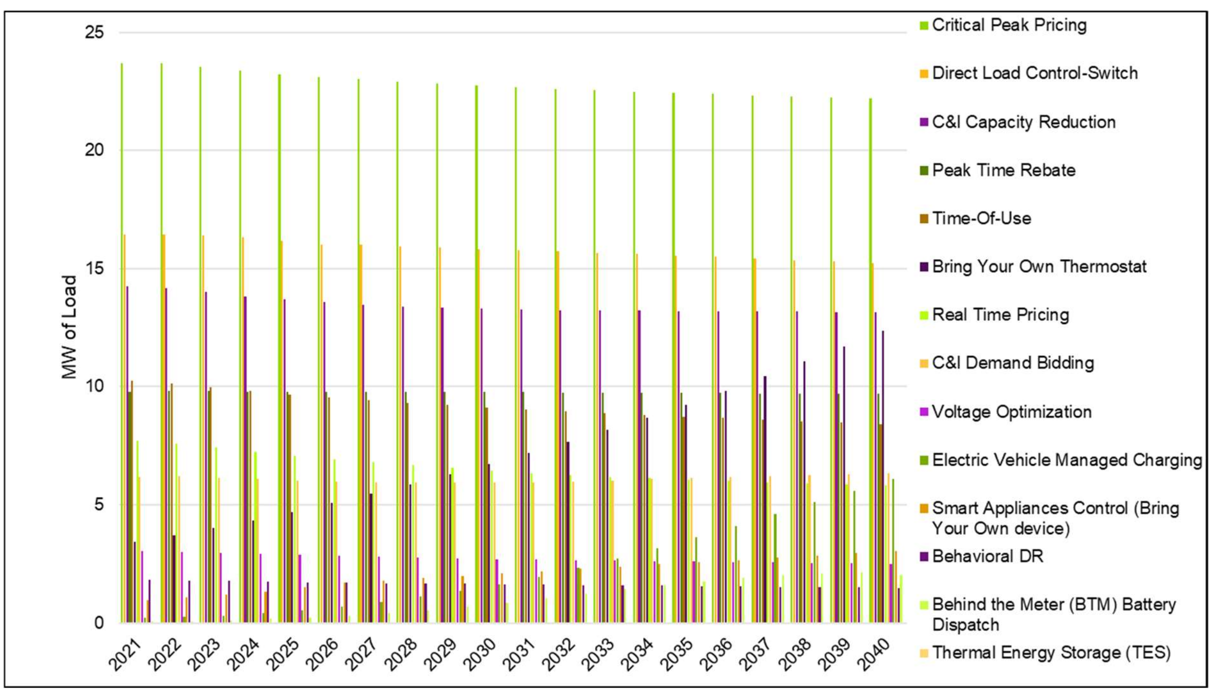
Figure C-3 and Figure C-4 show technical winter potential for the Peninsula and the Upper Peninsula, respectively.

Figure C-3. Technical Potential (MW) by Scenario for Lower Peninsula (Winter) from 2021-2040



Source: Guidehouse analysis

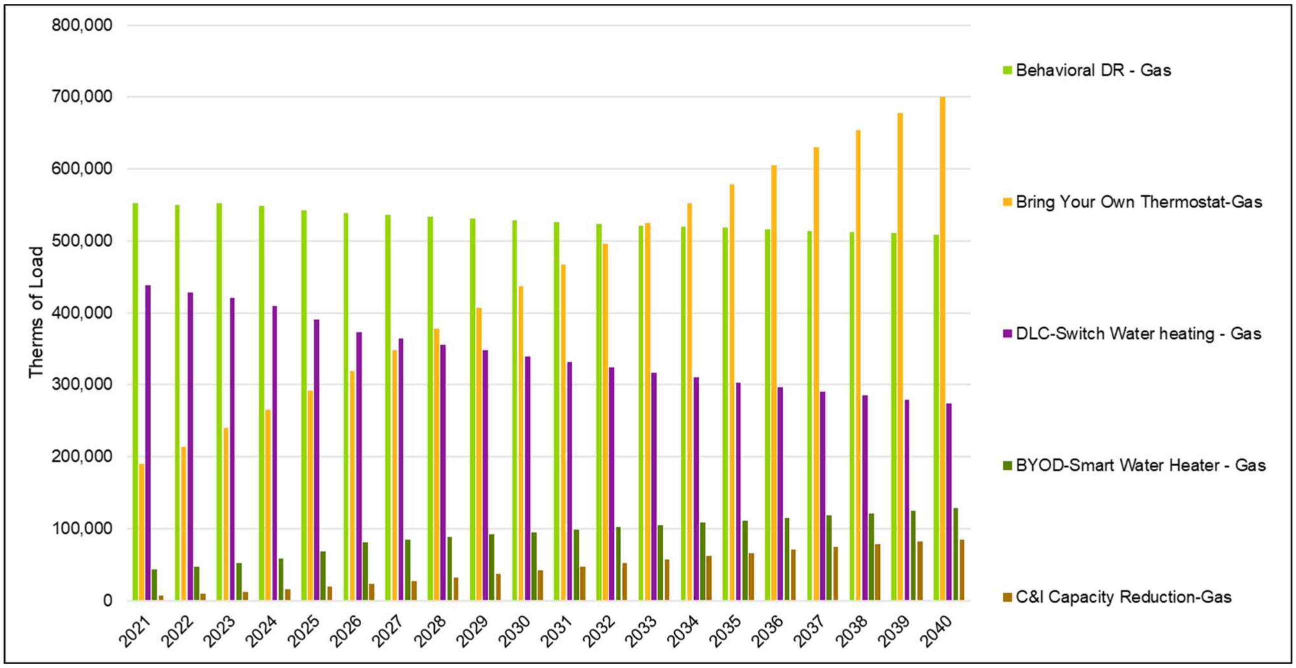
Figure C-4. Technical Potential (MW) by Scenario for Upper Peninsula (Winter) from 2021-2040



Source: Guidehouse analysis

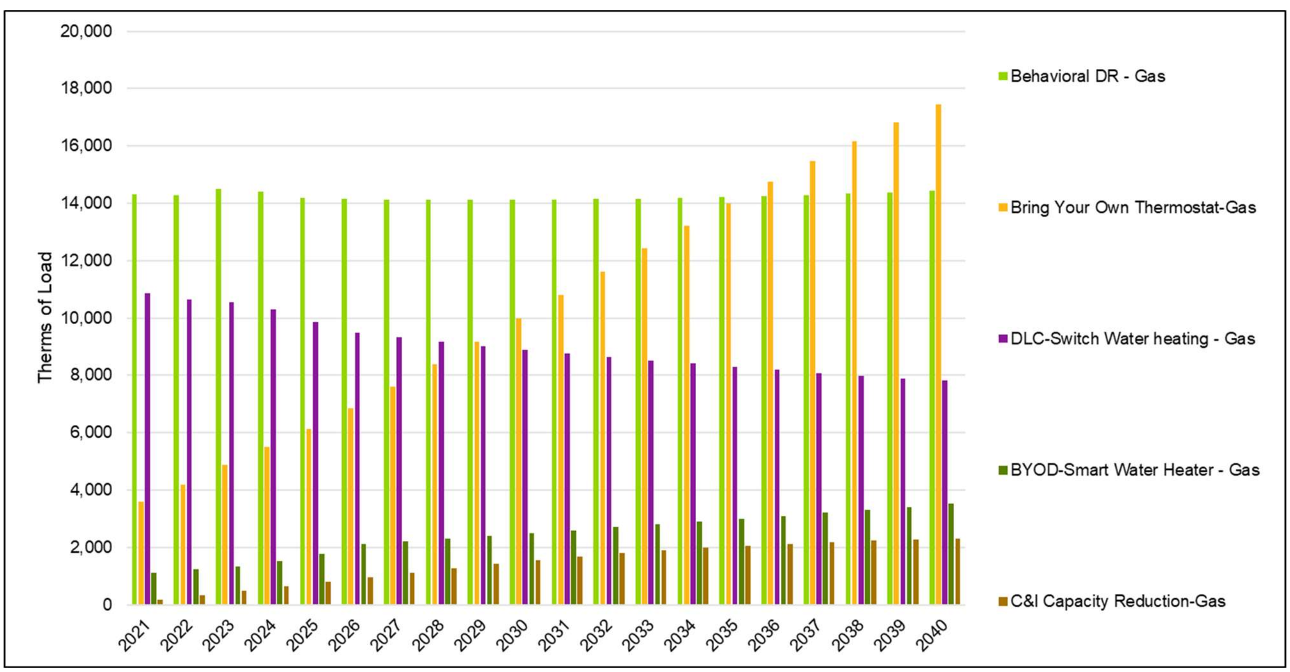
Figure C-5 and Figure C-6 show the technical natural gas DR potential for the Peninsula and the Upper Peninsula, respectively, for the winter peak period. The trends discussed for electric potential apply to the natural gas potential as well.

Figure C-5. Technical Potential (therms) by Scenario for Lower Peninsula (Winter) from 2021-2040



Source: Guidehouse analysis

Figure C-6. Technical Potential (therms) by Scenario for Upper Peninsula (Winter) from 2021-2040



Source: Guidehouse analysis

Appendix D. Demand Response Results File

[Note: Appendix D to be shared week of 8/23/2021]