Roadmap to Implementing

Michigan's New Energy Policy

Baseline Research Report

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List of Terms

AES – Alternative Energy Supplier

ACEC – Advanced Cleaner Energy Credit

ALJ – Administrative Law Judge

ATC – American Transmission Company

BTU – British thermal unit

CAA – Clean Air Act

CCR – Coal Combustion Residuals

CDD – Cooling degree day

CHP – Combined Heat and Power

CON – Certificate of Necessity

CPP – Clean Power Plan

CSAPR – Cross State Air Pollution Rule

CWA – Clean Water Act

CWIS – Cooling Water Intake Structures

DER – Distributed energy resources

DOE – Department of Energy

EE – Energy efficiency

EERS – Energy efficiency resource standards

EIA – Energy Information Administration

ENC – East North Central

EO – Energy optimization

EOC – Energy Optimization Credit

EPA – Environmental Protection Agency

FERC – Federal Energy Regulatory Commission

GW – Gigawatt

GWh – Gigawatt hour

HDD – Heating degree day

I &M – Indiana Michigan Power Company

IEEE – Institute of Electrical and Electronics Engineers

IPP – Independent Power Producer

IREC – Incentive Renewable Energy Credits

IRP – Integrated Resource Planning

kW – Kilowatt

kWh – Kilowatt hour

LSE – Load Serving Entity

MATS – Mercury and Air Toxics Standard

MCL – Michigan Common Law

MED – Major event day

MEO – Michigan Energy Office

MIRECS – Michigan Renewable Energy Certification System

MISO – Midcontinent Independent System Operator

Mcf – Thousand cubic feet

MMcf – Million cubic feet

MPSC – Michigan Public Service Commission

MW – Megawatt

MWh – Megawatt hour

NERC – North American Electric Reliability Council

NREL – National Renewable Energy Laboratory

NUG – Non Utility Generator

O & M – Operating and maintenance

PA – Public Act

PFD – Proposal for decision

PJM – Pennsylvania, New Jersey, and Maryland Interconnection

PPA – Power purchase agreement

PRMR – Planning reserve margin requirement

PSCR – Power supply cost recovery

PV – Photovoltaic

RCRA – Resource Conservation and Recovery Act

REC – Renewable Energy Credit

REP – Renewable Energy Plan

ROA – Retail open access

ROW – Right of way

RPS – Renewable Portfolio Standard

RTO – Regional Transmission Operator

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SWG – Solar Working Group

U.P. – Upper Peninsula

UCT – Utility cost test

UPPCo – Upper Peninsula Power Company

USRCT – Utility system resource cost test

VOS – Value of Solar

Section I. Introduction

Michigan's policy and business leaders, advocacy groups, and stakeholders are all engaged in dialogues about the state's future energy policy. Concurrently, the business landscape for electric utilities is shifting, due to factors like emerging technologies, changing economics of different fuel sources, state and federal policies, aging infrastructure, and regional wholesale electric market influences. Adapting to this shifting business landscape is challenging for utilities, primarily because the current utility regulatory model is based on new plant construction and electricity sales, (which are being eroded due to state and federal policies and new technology) and because of deficiencies in the existing electric delivery infrastructure (which limit integration of new technologies). To address these challenges and allow for successful implementation of the state's future energy policy, there will need to be enhanced coordination, thoughtful planning, and appropriate implementation of regulatory and utility ratemaking models.

In anticipation of changes to Michigan's energy policy, the Michigan Energy Office (MEO), with support from the U.S. Department of Energy (U.S. DOE), has undertaken a project to create a stakeholder- and research-driven roadmap for implementing new energy policies in a way that aligns utility business interests and customer behavior with public policy objectives. This project is directed by a multiagency steering committee, informed by a multisector stakeholder group, and supported with internal agency staff and external partners. The first step in this effort is to establish a common understanding of key elements related to the goals of this project, among project participants. To this end, the project steering committee has approved the *Roadmap for Implementing Michigan's Next Energy Policy Baseline Research Report.* This report will serve as a critical foundation for the roadmap process. It will provide an overview of Michigan's energy policy goals, help measure how Michigan utilities perform on key indicators, and review current relevant research related to changing economic and environmental conditions impacting the energy sector.

Where Are We Now?

Michigan's Energy Policies

Michigan's energy policy has undergone dramatic changes over the past 20 years. Historically, utilities have been vertically integrated, operating as natural monopolies. These firms controlled generation, transmission, and distribution of electricity across geographically defined service territories. Beginning in the early 1990s—following policy decisions at the national level—states began to seek alternatives to this traditional regulatory structure. The belief that a competitive supply of electricity would improve efficiency and lead to lower prices led states—including Michigan—to implement policies that would allow retail customers to choose their energy provider.

In June 2000, following several attempts to implement elements of retail restructuring by the Michigan Public Service Commission[1] (MPSC), the Michigan Legislature passed Public Act 141. Known as the customer choice and electricity reliability act—PA 141 restructured Michigan's electric power industry to allow customers to choose service from Alternative Energy Suppliers (AES). The law also limited the share of generating capacity a Michigan utility could control, implemented a five percent residential rate reduction, froze residential rate increases for five years and required regulated utilities divest their transmission assets or join a Regional Transmission Organization (RTO).[2] Michigan's approach to restructuring was different than restructuring efforts in other states in that, distribution utilities were allowed to maintain ownership of generation assets. These policies created Michigan's hybrid market structure where both regulated utilities and AESs sell electricity directly to customers.

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[1] In June 1999, the Michigan Supreme Court ruled that the MPSC lacked statutory authority to require a utility to transmit third-party provider's electricity through its system to a customer. For more information, see http://www.dleg.state.mi.us/mpsc/orders/courts/.
[2] Utilities divested their transmission assets, and transmission operators joined the Midcontinent Independent System Operator.

Following summers of tightly constrained power supplies the MPSC initiated an investigation into the state's future energy needs (MPSC 2004). The commission's report—released after the yearlong Capacity Needs Forum—determined that Michigan would need new baseload generation[3] to meet growing electricity demand by 2009, and given the state's current market structure, the MPSC stated, "it is unlikely that either traditional utilities or independent power producers (IPPs) will build new additional baseload generation without some departure from past practices for regulatory approval and rate treatment" (MPSC 2006). Following this determination, Governor Jennifer Granholm directed the MPSC to develop a comprehensive energy plan to address Michigan's short and long term electric needs (Granholm 2006).

Michigan's 21st Century Electric Energy Plan (referred to as the Plan) echoed the commission's earlier findings with regard to the need for new generating capacity and presented a range of policy recommendations to deal with the challenges presented by Michigan's market structure. The plan proposed policy changes designed to stabilize utilities' customer base and provide the regulatory certainty required to plan and finance new generation. In addition to the recommendations altering Michigan's regulatory framework, the commission's plan also proposed the state adopt a renewable energy standard and establish targets for energy optimization (EO).

In response to the MPSC's findings, the legislature overhauled Michigan's energy laws with the passage of Public Acts 286 and 295 of 2008. These bills changed the regulatory landscape and established new objectives for electric utilities in Michigan. Public Act 286 capped the amount of customers who could choose an AES, created the Certificate of Necessity (CON) proceeding and required utilities to institute cost of service rates[4]. Public Act 295 (PA 295)—known as the Clean, Renewable, and Efficient Energy Act—aimed to diversify Michigan's energy supply portfolio, increase consumption of indigenous resources, encourage private investment, and improve the quality of the environment (MCL 460.1001 2008). PA 295 established a Renewable Energy Standard mandating electric providers obtain 10 percent of their supply from renewable sources. The law also established an EO standard requiring electric and gas utilities to implement programs designed to reduce energy usage.

At the same time these reforms were being debated in the Legislature, the nation was entering into a prolonged economic recession. Instead of the projected growth in electricity consumption and subsequent need for new generation, statewide electricity consumption fell by more than 10 percent during the recession (U.S. EIA March 5, 2015). [5]

Governor's Policy Goals

In November 2012, Gov. Rick Snyder delivered a special message—"Ensuring our Future: Energy and the Environment." In it, he laid out his goals for Michigan's next energy policies. The governor's plan centers on designing policies that are adaptable, and allow the state and energy providers to make the right decisions even if conditions change. Starting with an approach that offers flexibility, the governor's plan also emphasizes improving reliability, making energy affordable, and protecting the environment (Snyder 2012).

In his address, Governor Snyder directed the MEO and MPSC to facilitate a review Michigan's current energy landscape through a comprehensive stakeholder engagement process. Over the course of 2013, as a part of the "Readying Michigan to Make Good Energy Decisions" process, the MEO and the MPSC conducted seven public meetings across the state and collected input from dozens of stakeholders. At the end of this process, the MEO and the MPSC published four reports: one on renewable energy, one on electric choice (deregulation), one on energy efficiency, and one on other issues, such as reliability and rates. These reports will inform the ongoing discussion of Michigan's energy policy.

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[3] Baseload generation is the electricity needed to supply round-the-clock energy demand.
[4] Until 2008, regulated rates were skewed, meaning that actual rates were not set at the cost of providing a service and certain customer classes were subsidizing others.
[5] The "Great Recession" officially lasted from December 2007 to June 2009, and was the longest period of economic downturn since the Great Depression (Isidore).

The governor's second special energy address delivered on March 13, 2015, built on the foundation described in his earlier message reiterating the importance of an adaptable energy plan. The governor delineated the following actions he believes the state must pursue to secure the state's energy future (Snyder 2015).

- We should meet at least 15 percent more of Michigan's energy needs in the next decade by eliminating energy waste.
- We need to eliminate artificial limits to the amount of waste reduction that utilities do. Right now, our law prevents utilities from spending more than 2 percent of their budget on waste reductions, even if that forces them to buy more expensive equipment instead.
- We need to make sure the MPSC can weigh the benefits of energy waste reductions in the same way it can weigh other kinds of expenses.
- We need to break out of the thinking that says the only compensation for waste reduction programs is to offset a loss, and instead make our smartest option a place where utilities want to invest. Capital invested in stopping energy waste should not be less valuable than capital invested in a new plant.
- We should repeal the on-bill financing ban for non-municipal utilities.
- When utilities propose big-dollar investments, we need to make sure those investments will keep down costs, provide reliability, and protect our environment.
- Some energy users, especially energy intensive industries, may be able to manage their energy use to go down when the grid starts to get strained, which will hold down costs and lower risks for everyone. We should make sure that we both create an opportunity and a reward for them to partner with our utilities to capture that savings.
- Michigan needs to complete plans to deploy smart meters that help utilities locate outages and restore power more quickly.
- Michigan needs to continue investing in infrastructure and maintenance to keep our power grid and pipeline system working smoothly and safely.
- We must change our electric market structure to ensure all electric providers are protecting their customers from massive outages due to lack of supply.
- We need to act now to make sure we have the tools to solve our own problems and keep decision-making in Michigan, not in Washington D.C.
- Finalize the transactions that will solve the Upper Peninsula's power crisis.
- Prevent the Lower Peninsula from developing the same crisis the U.P. is living through by reforming our electrical market to require every electric provider to protect its customers.

The governor's goals are sure to play an important role in the debate over Michigan's energy policies. There are currently several competing energy policy proposals being discussed in the legislature, but to date, no action has been taken by either the Michigan House or Senate. The governor has set an aggressive agenda for adopting new energy policy, calling for new legislation before the summer recess in June 2015.

Federal Environmental Regulations

A major factor in the considerations for Michigan's next energy policy will be the introduction of federal environmental regulations. While the electric power sector has faced increasingly stringent regulation over recent decades, the recently proposed Clean Power Plan is expected to have a dramatic impact on the future of electric power in the U.S. For a full discussion of the impacts of federal environmental regulations, see Section IV of this report.

Section II. Utility Performance Measures

This section summarizes how regulated utilities in Michigan are performing with respect to a number of key indicators. Defining a baseline for utility performance will allow us to compare and monitor over time how performance is impacted by regulatory and rate design changes.

Reliability and Grid Resilience

Distribution Reliability

A reliable electric supply is vitally important to both utilities and their customers. The MPSC requires regulated utilities to annually report on their performance based on two metrics commonly used to measure reliability. The two metrics—System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI)—measure the number and length of service interruptions, respectively. These standards are defined by the Institute of Electrical and Electronic Engineers (IEEE) Standard 1366 Guide for Electric Power Distribution Reliability Indices (IEEE 2012).

SAIFI is the average number of interruptions per customer for the year. It is determined by dividing the sum total number of customers interrupted by the total number of customers served during the year.

$$\frac{\textbf{Total Number of Customers Interrupted}}{\textbf{Total Number of Customers Served}}$$

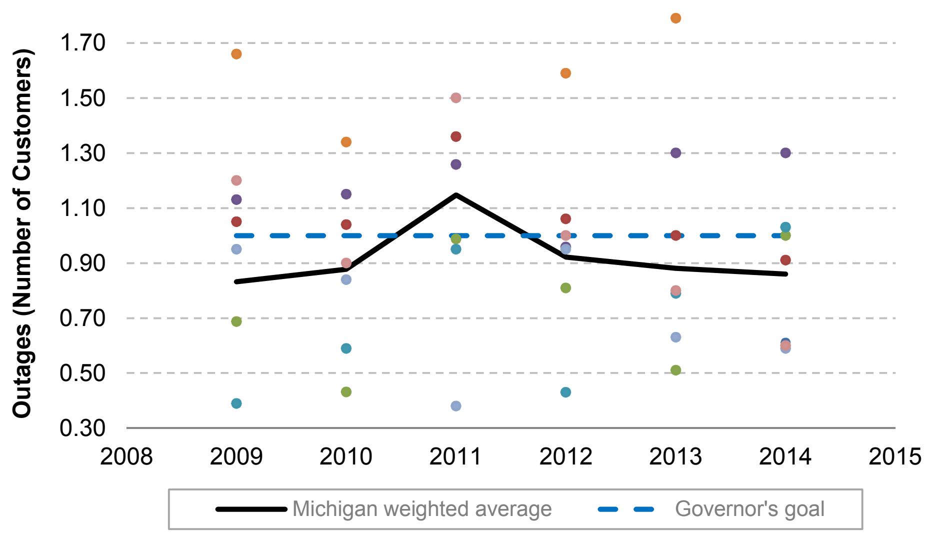
SAIDI is the average number of minutes of interruptions in a year per customer served. It is calculated by dividing the sum customer minutes interrupted by the total number of customers served.

$$\frac{\textbf{Total Customer Minutes Interrupted}}{\textbf{Total Number of Customers Served}}$$

The IEEE 1366 reliability metrics allow Michigan to be compared to national performance benchmarks compiled by IEEE's Distribution Reliability Working Group Annual Benchmark Study (IEEE). This enables the MPSC to compare Michigan's distribution reliability performance against other peer utilities across the country. The governor, with support from the MPSC, has established the goal that Michigan's utilities average no more than one customer interruption per year (SAIFI), and an average outage duration (SAIDI) of 150 minutes or less. MPSC staff analyzes these reliability metrics annually and provides updates to the governor's "Energy and Environment Dashboard".[6] Exhibits 2.1 and 2.2 show how Michigan's utilities perform on the SAIFI and SAIDI indices compared to the goals outlined by the governor.

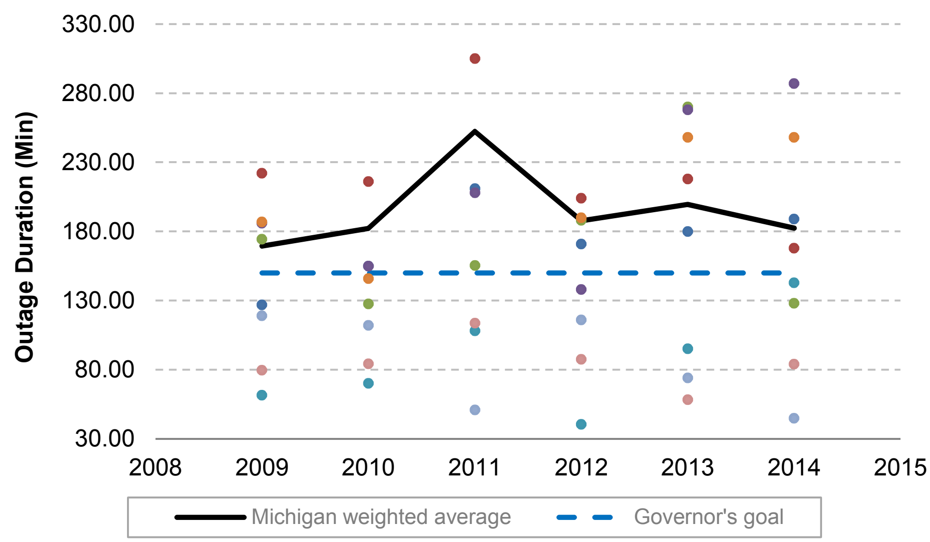
[6] Governor Snyder created a set of online dashboards to provide a quick assessment of the state's performance in key areas, including energy and the environment, health and education, and public safety. The dashboards can be accessed at https://midashboard.michigan.gov/

EXHIBIT 2.1. Outage Frequency (SAIFI), Excluding Major Event Days



NOTE: A major event day is an event that dramatically impacts the size and duration of an outage.
SOURCE: MPSC. N.d. *Utility Performance Data Filed Under Case No. U-12270.* Available at:
https://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=12270&submit.x=12&submit.y=13 (accessed 4/29/15)

EXHIBIT 2.2. Outage Duration (SAIDI), Excluding Major Event Days



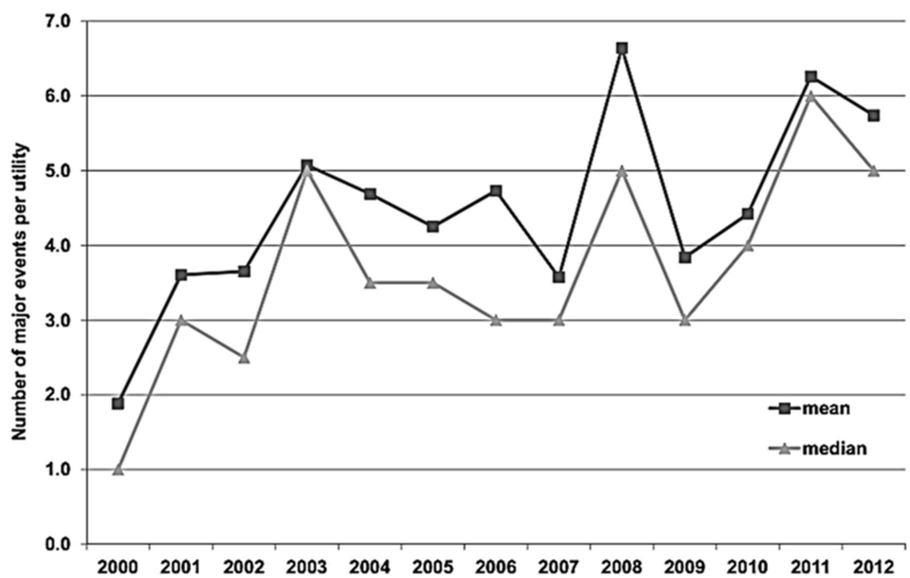
NOTE: A major event day is an event that dramatically impacts the size and duration of an outage.
SOURCE: MPSC. N.d. *Utility Performance Data Filed Under Case No. U-12270.* Available at:
https://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=12270&submit.x=12&submit.y=13 (accessed 4/29/15)

Weather and Reliability/Resiliency

SAIDI and SAIFI metrics are normally reported by utilities with and without major event days (MEDs) included. The definition of those events varies throughout the industry. The IEEE 1366 standard defines a "major event" as one that exceeds a specific threshold found by adding 2.5 standard deviations to the average of the natural logarithms of the electric utilities' daily SAIDI performance during the most recent five-year period (Warren n.d.). Stated simply, a major event day is an event that dramatically impacts the size and duration of an outage. Exhibits 2.4 and 2.5 show Michigan's average performance on SAIDI and SAIFI indices when MEDs are included.

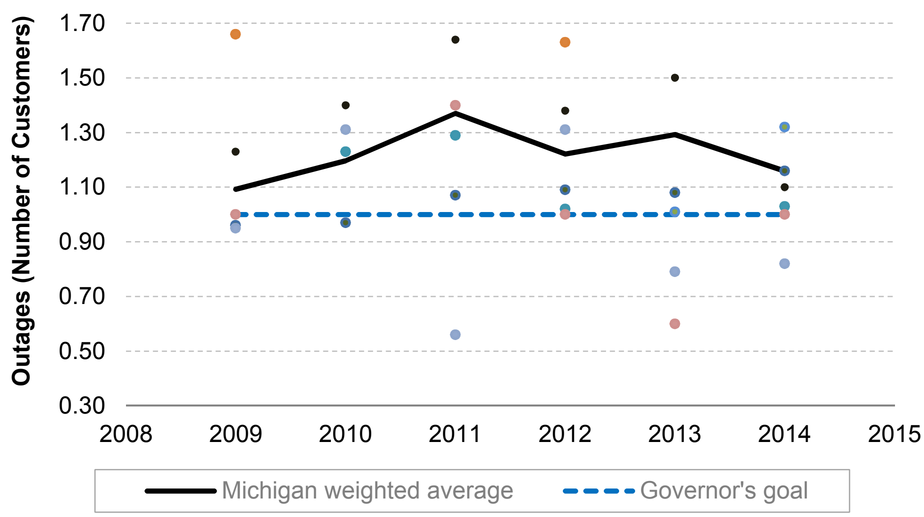
Power restoration during major weather events varies significantly from typical system restorations, often due to the scale of the outages and the restoration conditions utility workers are exposed to. These major events can significantly alter system outage metrics, such as SAIDI and SAIFI, and are often excluded to normalize data and separate operations into "daily" operations and "emergency" operations. As shown in Exhibit 2.3, over the last decade, there has been an increase in the frequency of MEDs.

EXHIBIT 2.3. Number of Annual Major Event Days, U.S., 2000–2012



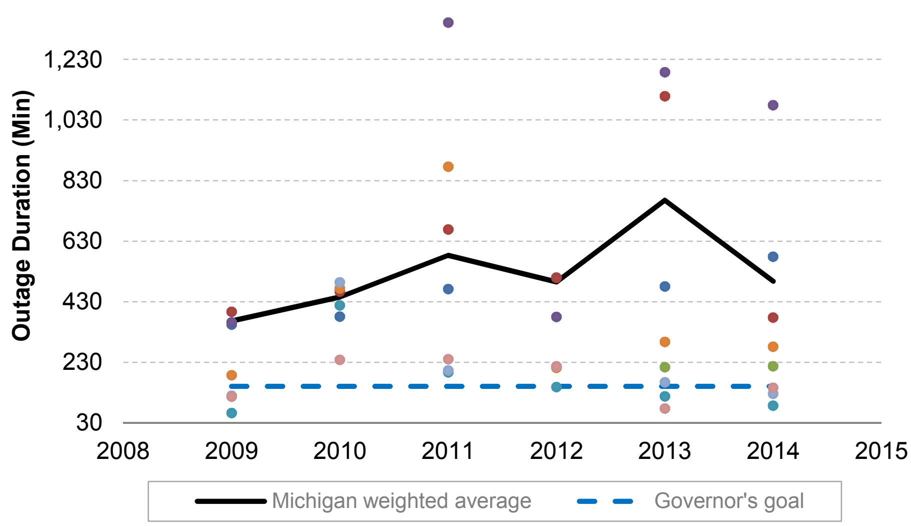
SOURCE: Joseph H. Eto. January 13, 2015. *Examination of Trends in Major Event Days Over Time, Considering the IEEE Benchmark Survey and Aspect of Std 1366.* Available at: http://grouper.ieee.org/groups/td/dist/sd/doc/2015-01%20Trends%20in%20Major%20Events%20Days%20over%20Time%20-Joseph%20Eto.pdf (accessed 4/15/2015)

EXHIBIT 2.4. Michigan Outage Frequency (SAIFI), Including Major Event Days



SOURCE: MPSC. N.d. *Utility Performance Data Filed Under Case No. U-12270.* Available at: https://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=12270&submit.x=12&submit.y=13 (accessed 4/29/15)

EXHIBIT 2.5. Michigan Outage Duration (SAIDI), Including Major Event Days



SOURCE: MPSC. N.d. *Utility Performance Data Filed Under Case No. U-12270.* Available at: https://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=12270&submit.x=12&submit.y=13 (accessed 4/29/15)

Improving Reliability

In an attempt to combat this growing number of MEDs, utilities are increasing investments in resilient distribution assets that are capable of diagnosing, reporting, and sometimes repairing themselves without the need for utility employees to address the issue. These advanced distribution assets will provide system operators increased insight into utility outages, thereby improving the efficiency of future outage restoration efforts. Given the size of Michigan's distribution infrastructure, wholesale replacement of all distribution assets with the latest technology would not be economically feasible. However, as these advanced technologies become more prominent in the distribution system, through the natural attrition of outdated distribution assets, it would be expected that significant improvements in outage response will be realized.

Another way in which utilities are combating this increase in major events is to modify current operation and maintenance (O&M) programs to address concerns that typically arise during these major events, such as trees outside of the utilities' right-of-way (ROW). Hazardous trees[7] outside the utility ROW pose a significant threat to utility infrastructure during periods of heavy snow/ice loads. High winds often associated with MEDs and removal of hazardous trees are not addressed in typical maintenance. In 2015, DTE Energy (DTE) and Consumers Energy (Consumers) will deploy hazardous tree removal programs to limit the effect these trees have on outages during major events (MPSC *Order in Case No. U-17542* December 4, 2014). These special O&M programs, as well as consistent investment in system, will play a large part in mitigating the reliability/resiliency issues caused by major events on the electric grid.

Michigan's two largest utilities have recently begun programs to make their electric grid more resilient and decrease the average time customers are without power. In addition, to hazardous tree removal programs and investments in advanced distribution technology, Consumers and DTE are investing more money in existing programs that increase reliability. The two utilities have proposed to spend more money on vegetation management to increase miles of ROW trimmed and decrease the cycle time on their electric circuits. Consumers has also proposed to significantly increase spending on reliability, asset relocations and technology projects. These investments will strengthen the system, make it more resilient and enable quick restoration.

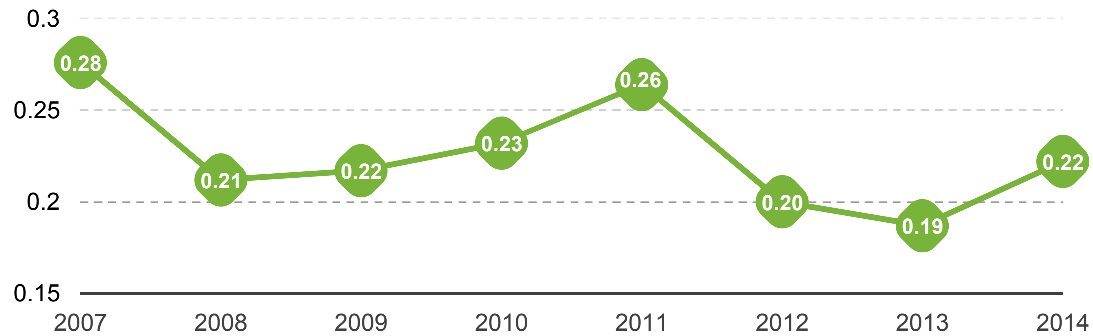
DTE's new "Efficient Frontier" program is designed to improve reliability and customer satisfaction through four measures. First is an enhancement to the vegetation management program to prevent outages. Second is a continuous improvement effort to the company's Repetitive Outage Program. Third is a program to reduce the number of customers affected and improve the restoration time when outages do occur. Fourth is increasing the maintenance activity for key distribution assets. As a result of these programs, both companies' reliability indexes should improve noticeably in the next few years.

Transmission Reliability

ITC Transmission, METC[8], American Transmission Company (ATC), Indiana Michigan Power Company (I&M), and Wolverine Power Cooperative (Wolverine) are the most prominent transmission companies in Michigan. Although these companies own the transmission facilities, the facilities in Michigan are operated by RTOs. These regional entities oversee the transmission grid and coordinate electric supply and delivery across their regional footprint. RTOs also play a major role in planning transmission expansion and enhancements. Michigan belongs to two RTOs—the Midcontinent Independent System Operator (MISO) and the Pennsylvania, New Jersey and Maryland Interconnection (PJM). Each of these RTOs conducts annual transmission planning for their service territories (MISO November 11, 2014 and PJM 2014). As a part of his Energy and Environment Dashboard the governor has asked the MPSC to track performance of Michigan's transmission system and report the number of electric transmission line outages that occur each year. Michigan's transmission system performed consistently on this metric over the past eight years. This information is displayed in Exhibit 2.6.

[7] Hazardous trees are identified as those that are structurally unsound, dead, or diseased trees that pose an imminent threat to utility assets.
[8] ITC Transmission and METC are both wholly owned subsidiaries of ITC Holdings Corporation, and for the purposes of this report will be referred to as ITC Michigan.

EXHIBIT 2.6. Michigan Electrical Transmission Line Outages, Weighted Average Per Circuit



SOURCE: State of Michigan. May 5, 2014. *Energy and Environment Dashboard.* Available at: https://midashboard.michigan.gov/energy-and-environment. (accessed 3/21/2015)

Michigan's transmission system is a part of the Eastern Interconnection—the transmission grid covering states from the Rocky Mountains to the Atlantic Ocean and including neighboring Canadian provinces. Michigan has high voltage connections to neighboring states including Wisconsin, Ohio, and Indiana. Currently, there is no high voltage transmission connection between the Upper and Lower Peninsulas. Exhibit 2.7 shows where Michigan's major transmission lines are located.

EXHIBIT 2.7. Major Electric Transmission Lines (≥ 345kV)

SOURCE: U.S. Energy Information Administration. November 2014. *Michigan State Profile and Energy Estimates.* Available at: http://www.eia.gov/state/?sid=MI. (accessed on 1/22/2015)

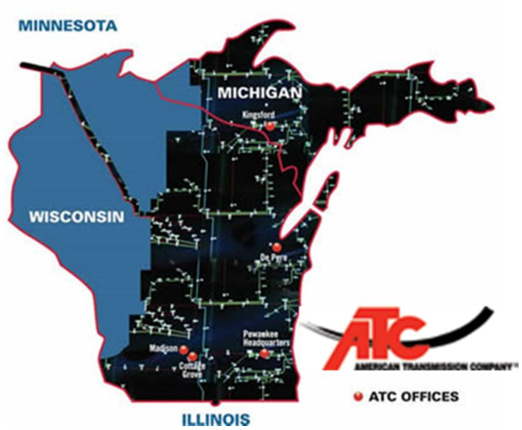
ITC Michigan (ITC) is the primary transmission owner in the Lower Peninsula. Its service territory is depicted in Exhibit 2.8. ITC participates in the SGS Statistical Services Transmission Reliability Benchmarking Study with other transmission owners across the United States. The SGS study benchmarks transmission performance with 14 transmission owners/operators across the United States. These companies represent 30 percent of the United States/Canadian transmission grid based on North American Electric Reliability Corporation (NERC) bulk power line mileage. This effort measures a participant's reliability performance against its peers. ITC's transmission system, performs in the top 25 percent of all participants, and has often ranked in the top 10 percent of utilities for the lowest average number of sustained outages per circuit (ITC 2014). ITC continues to invest in transmission grid reliability through annual maintenance projects, asset renewal projects, and transmission expansion projects. ITC's annual projects include breaker, pole, relay, and capacitor replacements. Some of their larger key reliability projects are highlighted in Appendix A.

EXHIBIT 2.8. ITC Michigan Service Area

SOURCE: ITC Transmission. N.d. ITC Michigan. Available at: www.itc-holdings.com/itc-michigan.html. (accessed on 1/22/15)

ATC is the primary transmission owner for Michigan's Upper Peninsula. Its service territory is depicted in Exhibit 2.9. ATC transmission line reliability was rated a top performer in the 2013 SGS Statistical Services Transmission Reliability Benchmarking Study highlighted by "Best in Class" for 100–161 kV, "Top Decile" for 345-500 kV and "Top Quartile" for subtransmission voltage classes (ATC 2015). A summary of ATC's transmission planning is available in Appendix B.

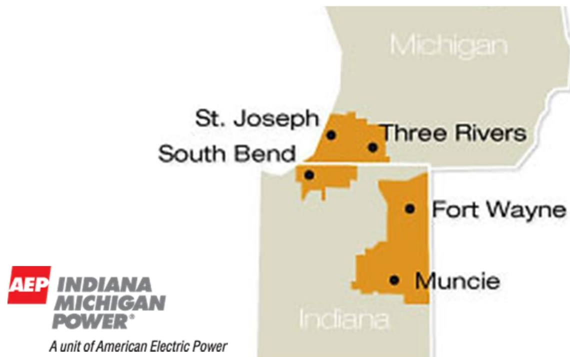
EXHIBIT 2.10. American Transmission Company Service Area



SOURCE: American Transmission Company. N.d. Service Territory. Available at: http://www.atcllc.com/about-us/service-area/. (accessed on 1/22/15)

I&M owns transmission in the southwestern portion of Michigan's Lower Peninsula (see Exhibit 2.11). I&M continues to undertake transmission projects that enhance system reliability and resiliency. Generally, these projects address issues pertaining to transmission outages, capacity deficiency, resource unavailability, and existing transmission infrastructure condition. A list of some of I&M's recent reliability projects can be found in Appendix C.

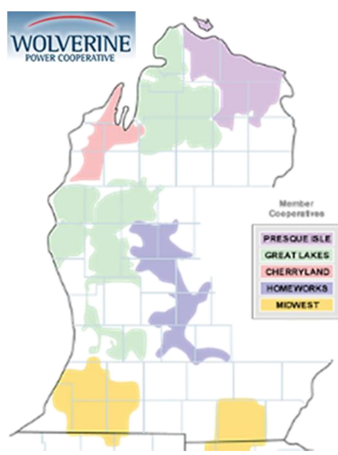
EXHIBIT 2.11. Indiana Michigan Power Company Service Area



SOURCE: Indiana Michigan Power. N.d. *Service Territory.* Available at: https://www.indianamichiganpower.com/info/facts/ServiceTerritory.aspx. (accessed on 1/22/15)

The Wolverine Power Cooperative's transmission network has five member utilities that together serve customers in 40 counties in Michigan's Lower Peninsula (see Exhibit 2.12). The company has taken several steps to improve the reliability and resiliency of their transmission system by rebuilding old and undependable equipment, replacing old poles, reconfiguring substations, conducting system protection equipment upgrades, improving emergency response programs, and improving vegetation management.

EXHIBIT 2.12. Wolverine Power Cooperative Service Area



SOURCE: Wolverine Power Cooperative. n.d. *Members.* Available at: https://www.wpsci.com/Members.aspx (accessed 4/15/15)

Within the past ten years, Wolverine has rebuilt roughly 25 percent of its transmission system. The rebuilt facilities are designed for future conversion to a higher operating voltage by utilizing a substantially larger conductor and increasing the line clearances. The new design results in reduced transmission losses, increased ground and conductor spacing clearances, improved lightning protection, and increased conductor capacity.

In addition to line rebuild projects, Wolverine's station reconfiguration projects and protection equipment projects have helped to reduce the risk of single element failures that can cause multiple elements to trip offline. To reduce or eliminate this possibility, Wolverine has been upgrading stations with a ring bus or breaker-and-a-half bus because these configurations help to isolate the cause of a failure. Installing protective equipment such as air break switches and protective digital relays helps to respond to a variety of system events directly from Wolverine's Energy Control Center allowing for faster accurate control.

Transmission Reliability—Vegetation Management

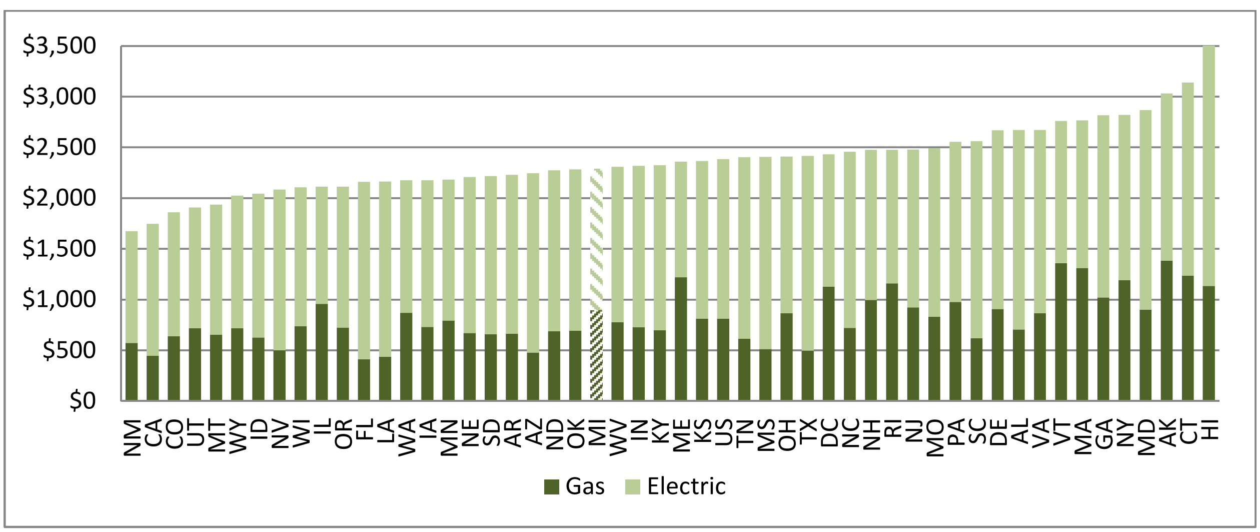
Transmission companies are presented with the unique challenge of balancing vegetation management and environmental stewardship during construction and full operation. The risks associated with vegetation interference with transmission lines can be significant. Failure to adequately trim and maintain trees on a rural 345 kV line in Ohio left 50 million people without power for two days during August 2003. In the wake of that and other smaller outages, Congress passed the Energy Policy Act of 2005. This required the Federal Energy Regulatory Commission (FERC) to review, develop, and enforce mandatory reliability standards pertaining to vegetation management for the bulk power system. Those standards include requirements to prevent vegetation encroachments into a minimum clearance distance from the line, prepare and update a formal transmission vegetation management program, implement an annual work plan, and report sustained outages for qualified lines (FERC 2013).

Michigan's transmission companies continue to improve vegetation management practices and apply industry best practices within their respective companies—while balancing efforts to preserve the state's complex and beautiful scenery. Michigan transmission companies evaluate transmission ROW distances for adequate clearance and vegetation trimming cycles that may be impacted by local vegetation growth rates, diseases, and invasive species, such as the emerald ash borer. Transmission companies are required to follow all environmental rules and regulations that apply in the area during construction and ongoing operation of the transmission system.

Affordability

Governor Snyder has set a goal for energy affordability in Michigan–that state residents' total energy bills (electricity and heating) should not be higher the national average (Snyder 2015). That goal is being achieved; the average Michigan residential customer's energy bill is 4 percent lower than the U.S. average, as shown in Exhibit 2.13 (U.S. EIA March 31, 2015).

EXHIBIT 2.13. 2013 Residential Electric and Natural Gas Average Bills by State



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SOURCE: U.S. Energy Information Administration (U.S. EIA). March 31, 2015. *Electric power sales, revenue, and energy efficiency Form EIA-861.* Available at: http://www.eia.gov/electricity/data/state/ (accessed 4/2/15), U.S. EIA. April 30, 2015. *Natural Gas Consumption by End Use.* Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vrs_mmcf_a.htm (accessed 4/30/15), U.S. EIA. April 30, 2015. *Number of Natural Gas Consumers.* Available at: http://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN3_Count_a.htm (accessed on 4/30/2015), U.S. EIA. April 30, 2015. *Natural Gas Prices.* Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_a.htm (accessed on 4/30/2015)

Another way to look affordability is to compare the amount that customers spend on energy compared to the median household income. The portion of household income Michigan residents spend on electricity and natural gas bills is very near the national average. The median household income for Michigan is $47,793. The average Michigan customer spends 4.57 percent of their income on electricity and natural gas. The median household income for the U.S. is $52,176. Combined electric and natural gas spending accounts for 4.52 percent of median household income (U.S. Census Bureau October 23, 2014).

Consumption Patterns

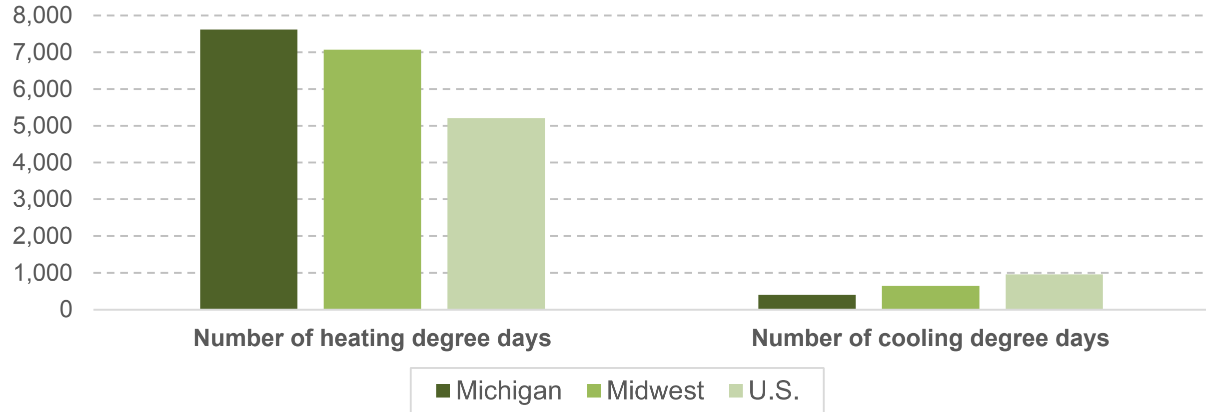
To get a better understanding of affordability, it is helpful to look at factors that contribute to energy consumption. Total energy bills are a function of consumption and price. A major driver impacting energy consumption is regional climate. Residential heating and cooling account for almost half of an average household's total energy consumption (U.S. EIA January 11, 2013). Heating degree days (HDDs) and cooling degree days (CDDs) are common measures of weather-related energy usage.[9] An HDD is calculated as 65 minus the daily average temperature, while a CDD is calculated as the daily average temperature minus 65. When the average temperature is below 65, there are no CDDs; when it is above 65, there are no HDDs. Further, HDDs and CDDs are often weighted by the population of the region they are describing. The National Weather Service explains:

> *"The energy demand for a region, such as a state, depends on where people live. Temperatures in sparsely populated regions, such as the mountains, have less impact on regional energy demand than temperatures within large cities. Thus, regional energy demand is often estimated by population weighted statistics, rather than area averages." (NWS n.d.)*

As shown in Exhibit 2.14, in 2014, Michigan experienced fewer CDDs and more HDDs than the averages of both the U.S. and the Midwest (NWS January 2, 2015). This leads to less energy demand for seasonal cooling and more energy consumed for home heating. Exhibit 2.15 shows the ten-year population-weighted average annual HDDs and CDDs by census region. Michigan is in the East North Central region, along with Illinois, Indiana, Ohio, and Wisconsin. This region experiences 44 percent more HDD and 42 percent fewer CDDs than the U.S. average.

[9] A "heating degree day" is not a calendar day, but an index that measures the difference of a daily average temperature from 65 degrees Fahrenheit. For example, heating degree days for a station with daily mean temperatures during a seven-day period of 59, 50, 42, 36, 20, 10 and 45, are 6, 15, 23, 29, 45, 55, and 20, for a weekly total of 193 heating degree days (over the seven calendar days).

EXHIBIT 2.14. Heating and Cooling Days, 2014



NOTE: In charts where the term Midwest is used, the term refers to Michigan, Indiana, Illinois, Ohio, and Wisconsin.
SOURCE: National Weather Service (NWS). January 2, 2015. Degree Day Statistics. Available at: ftp://ftp.cpc.ncep.noaa.gov/htdocs/degree_days/weighted/daily_data/. (accessed on 2/24/2015)

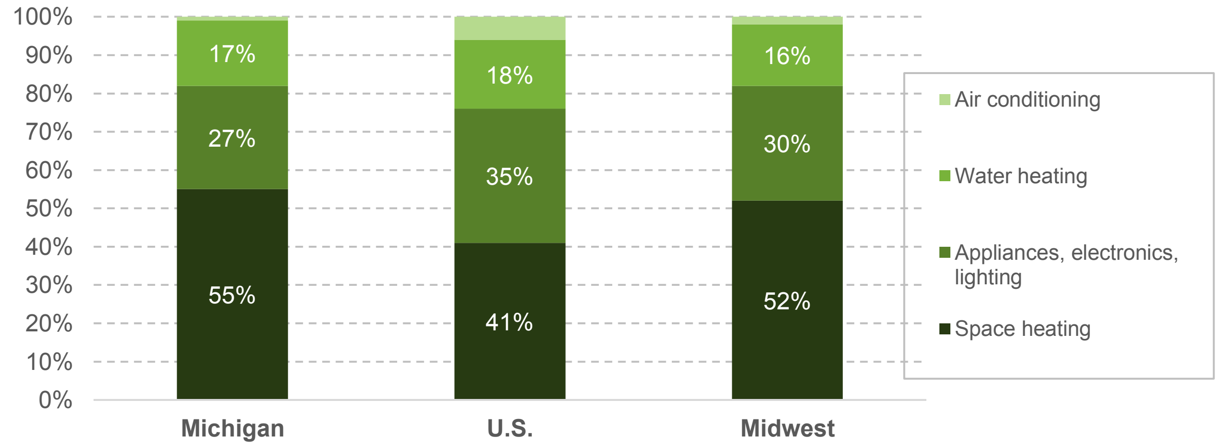
EXHIBIT 2.15. Ten-year Population-weighted Averages

Region	HDD	CDD	HDD/US	CDD/US
New England	6,289	500	1.46	0.37
Middle Atlantic	5,636	730	1.31	0.54
East North Central	**6,170**	**785**	**1.44**	**0.58**
West North Central	6,449	972	1.50	0.71
South Atlantic	2,679	2,112	0.62	1.55
East South Central	3,402	1,666	0.79	1.22
West South Central	2,075	2,680	0.48	1.97
Mountain	5,038	1,431	1.17	1.05
Pacific	3,511	839	0.82	0.62
US Average	4,298	1,361	1.00	1.00

SOURCE: U.S. EIA. April 7, 2015. *Short-Term Energy Outlook Table 9c.* Available at: http://www.eia.gov/forecasts/steo/tables/pdf/9ctab.pdf. (accessed 3/21/2015)

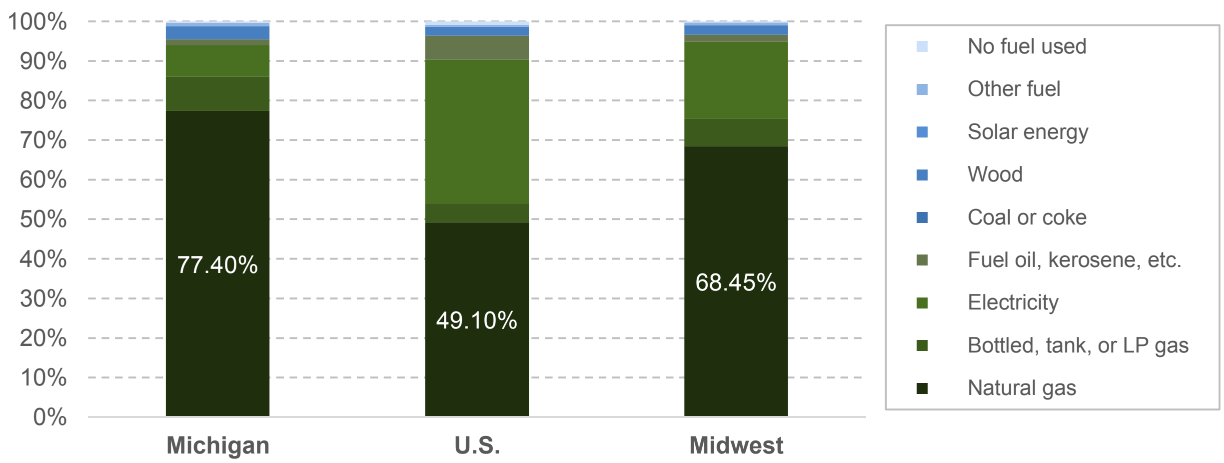
Due to the temperate climate, relatively mild summers, and cold winters, households in Michigan consume relatively little energy for air conditioning, and more energy for seasonal heating, as shown in Exhibit 2.16 (U.S. EIA January 2013). Lower demand for air conditioning and high seasonal heating needs contribute to Michiganders consuming less electricity and more of other heating fuels than the national average, as shown in Exhibit 2.18. Nearly 80 percent of homes rely on natural gas for heat, far more than the national average, as shown in Exhibit 2.17. Michigan’s residential natural consumption is fourth highest in the nation, and the state is the ninth in total natural gas consumption. See Exhibit 2.19 for complete electric and natural gas consumption rankings for Michigan by sector.

EXHIBIT 2.16. Household Energy Consumption by End Use, 2009



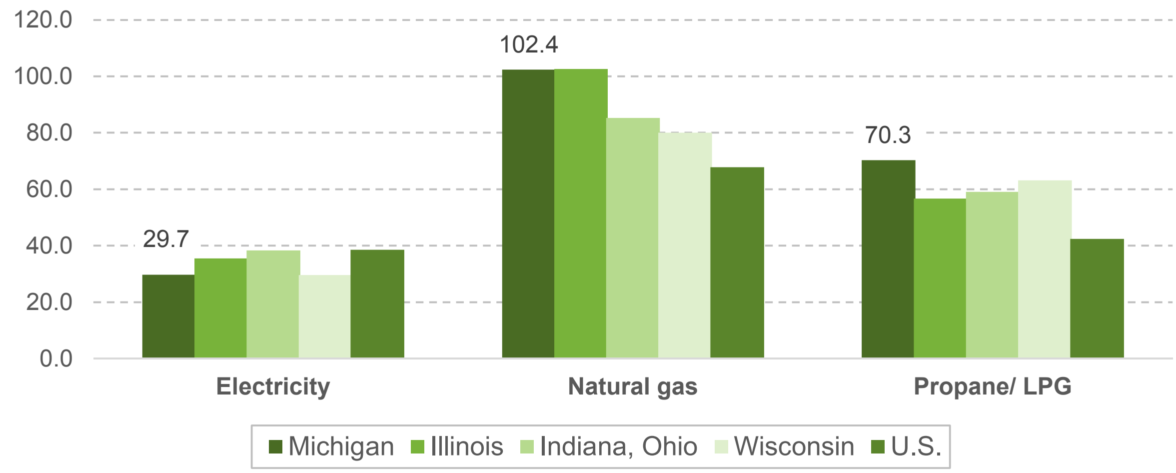
SOURCE: U.S. EIA. January 11, 2013. *2009 Residential Energy Consumption Survey*. Available at: www.eia.gov/consumption/residential/data/2009/index.cfm?view=consumption. (accessed on 1/18/2015)

EXHIBIT 2.17. Household Heating Source, 2013



SOURCE: U.S. EIA. January 11, 2013. *2009 Residential Energy Consumption Survey*. Available at: www.eia.gov/consumption/residential/data/2009/index.cfm?view=consumption. (accessed on 1/18/2015)

EXHIBIT 2.18. Average Household Energy Consumption by Fuel (mBtu), 2009



Data for Indiana and Ohio was combined in the 2009 Residential Energy Consumption Survey.
SOURCE: U.S. Energy Information Administration. January 11, 2013. 2009 Residential Energy Consumption Survey. Available at: http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=consumption. (accessed on 1/18/2015)

EXHIBIT 2.19. Natural Gas and Electricity Consumption National Rank, Michigan, 2013

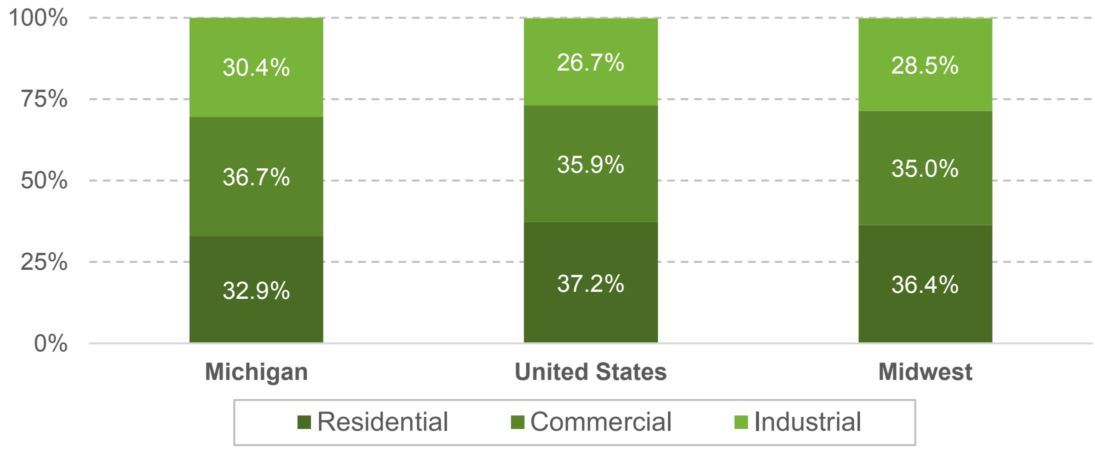
	Residential Consumption	Commercial Consumption	Industrial Consumption	Electric Power Consumption	Transportation Consumption	Total Consumption
Natural gas	4	6	11	18	10	9
Electric	14	12	10	n/a	25	12

SOURCE: U.S. Energy Information Administration. November 8, 2013. Electric Sales, Revenue, and Price. Available at: http://www.eia.gov/electricity/data/state/sales_annual.xls. (accessed on 1/18/2015) and U.S. Energy Information Administration. January 30, 2015. Natural Gas Prices. Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SMI_a.htm. (accessed on 1/18/15)

Electricity Prices

Electric customers are generally divided into three categories—industrial, commercial, and residential. These groups are organized based on the characteristics of their energy needs and the costs of providing various services to them. Prices charged to customer classes will vary based on their electric supplier's individual rates. Exhibit 2.20 shows the distribution of energy consumption between different customer classes.

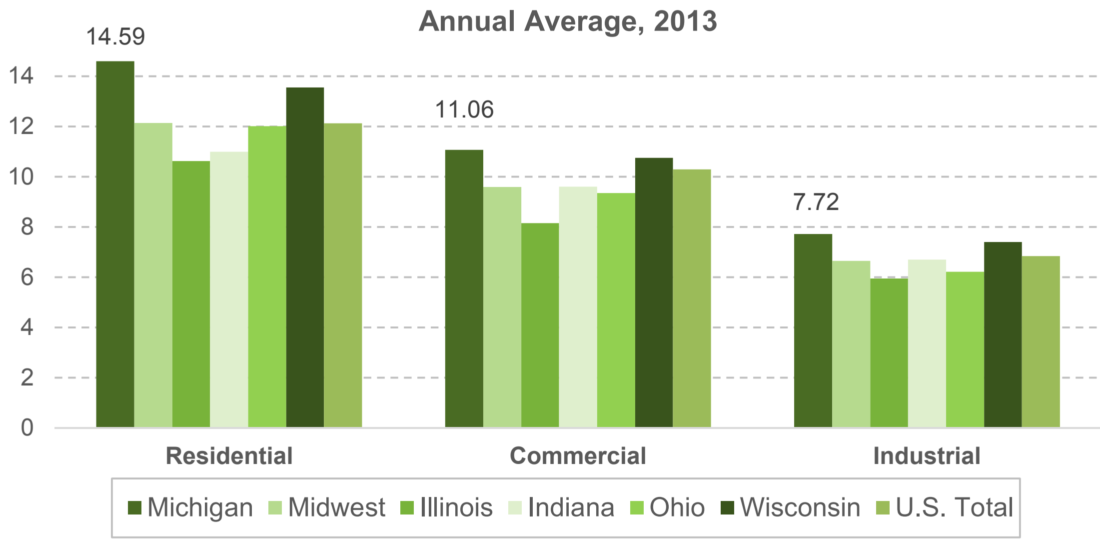
EXHIBIT 2.20. Percentage of Total Retail Electricity Sales (MWhs) by End Use, 2012

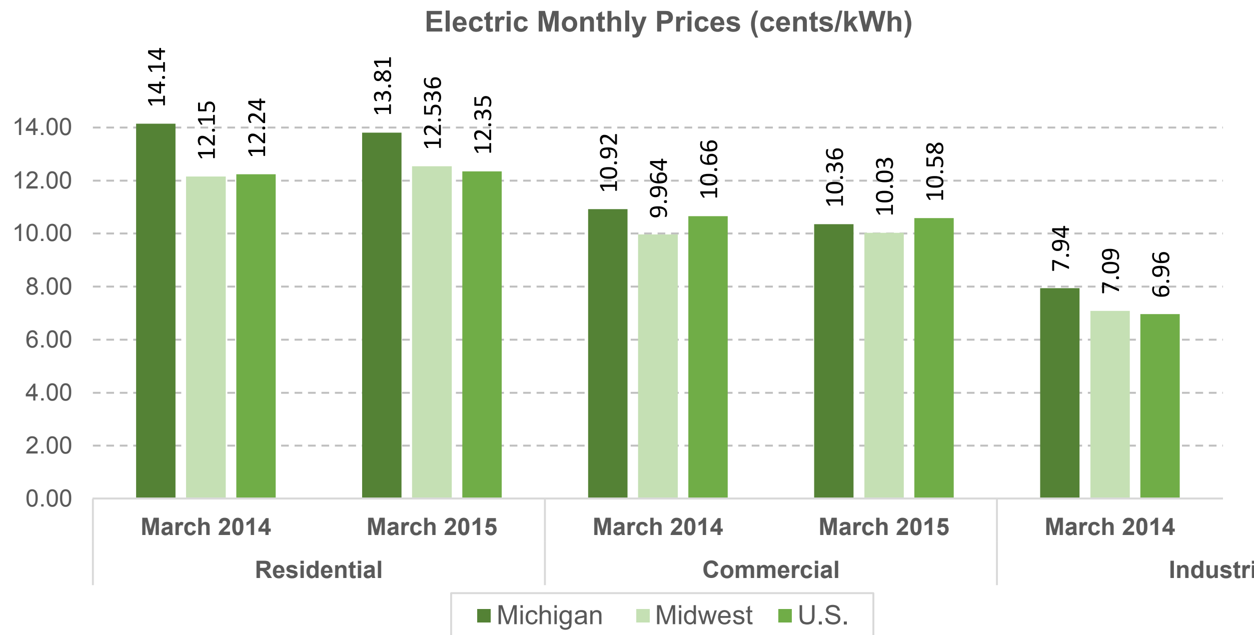


SOURCE: U.S. Energy Information Administration. November 8, 2013. *Electric Sales, Revenue, and Price*. Available at: http://www.eia.gov/electricity/data/state/sales_annual.xls. (accessed on 1/18/2015)

As shown in Exhibit 2.21, Michigan's electric rates are above the national average, and the highest among neighboring states for each customer class. Michigan's average residential price is 20.34 percent higher than the U.S. average, which is the 11th highest among the states. For commercial and industrial prices, Michigan ranks 14th and 16th highest, respectively.

EXHIBIT 2.21. Average Retail Price of Electricity (cents/kWh)



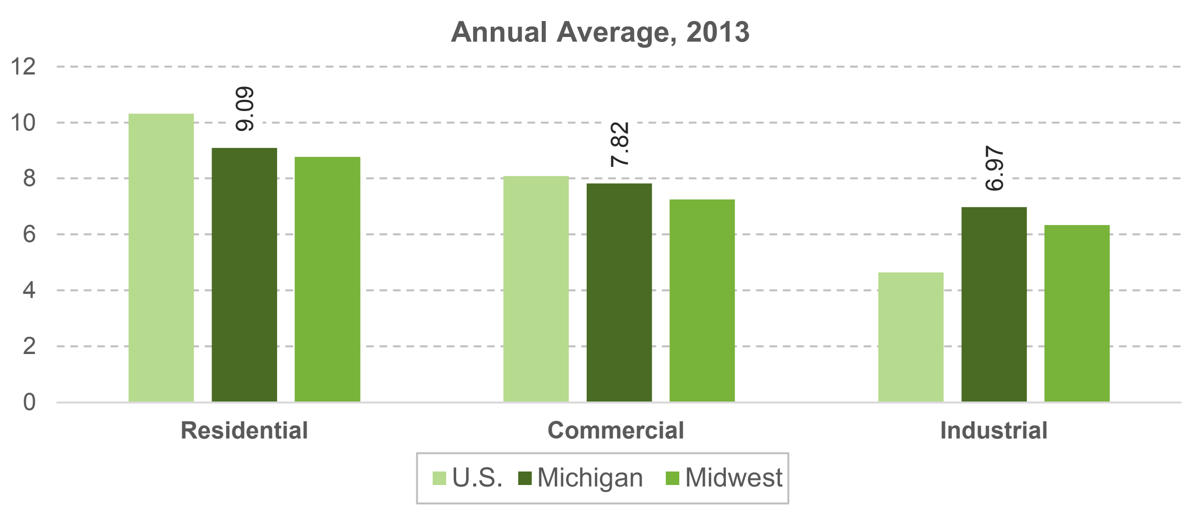


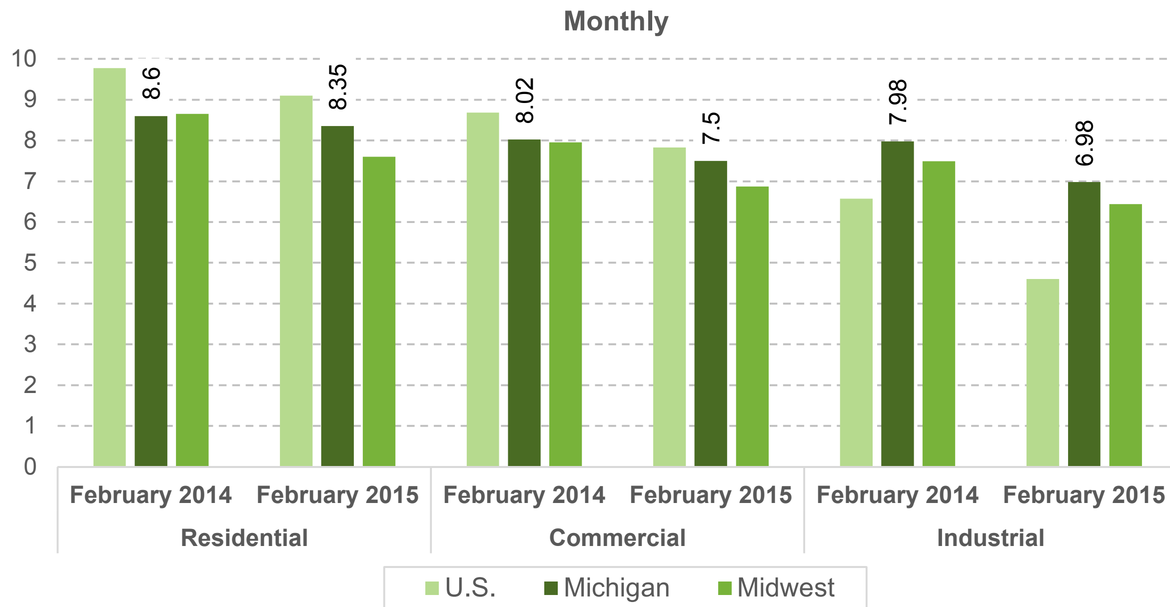
SOURCE: U.S. EIA. March 23, 2015. *2013 Total Electric Industry- Average Retail Price (cents/kWh) EIA-861*. Available at: http://www.eia.gov/electricity/sales_revenue_price/pdf/table4.pdf. (accessed 4/30/2015)

Natural Gas Prices

Residential natural gas consumption in Michigan is higher than the national average, due largely to seasonal heating demands. As shown in Exhibit 2.22, the price of natural gas for residential and commercial customers is below the national average, but still higher than the prices in neighboring states (U.S. EIA January 2015).

EXHIBIT 2.22. Natural Gas Prices (dollars/thousand cubic feet)





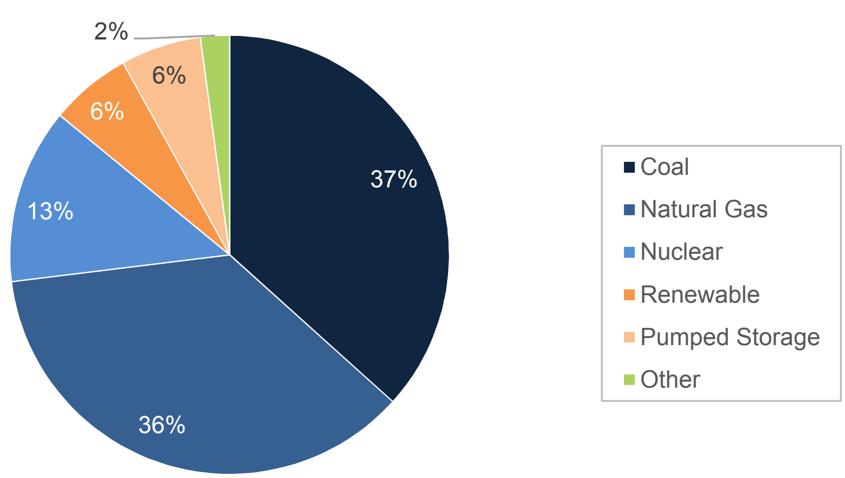
SOURCE: U.S. Energy Information Administration. January 30, 2015. *Natural Gas Prices.* Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SMI_a.htm. (accessed on 1/18/15)

Resource Diversity and Renewables

Michigan's Portfolio

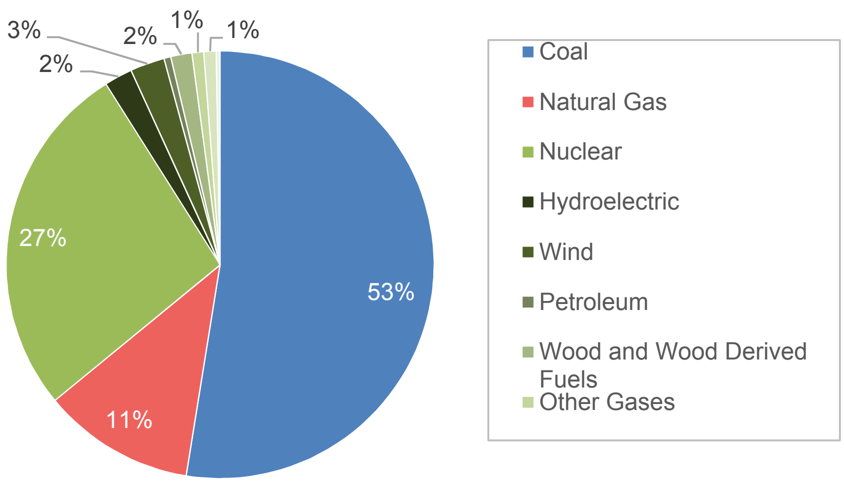
Michigan's electric generating portfolio is dominated by three main fuel sources—coal, natural gas, and nuclear. Exhibit 2.23 shows the generation capacity by fuel source in 2013, and Exhibit 2.24 shows actual amount of electricity generated by fuel source in 2013.

EXHIBIT 2.23. Michigan Generation Nameplate Capacity by Fuel Type, 2013 (MW)



SOURCE: U.S. EIA. February 17, 2015. *Form EIA-860*. Available at: http://www.eia.gov/totalenergy/data/monthly/. (accessed 3/21/2015)

EXHIBIT 2.24. Total Electricity Generated, All Producers, 2013 (MWhs)

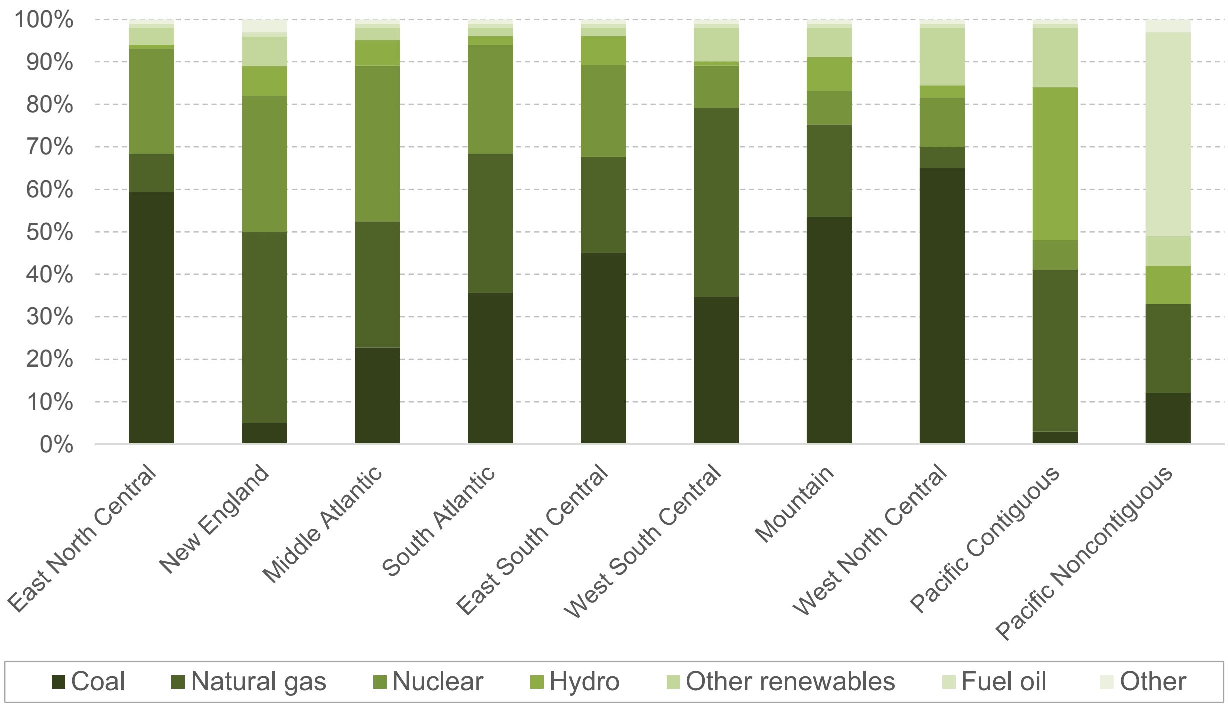


SOURCE: U.S. EIA. March 25, 2015. *Form EIA-923*. Available at: http://www.eia.gov/electricity/data/eia923/. (accessed 4/4/2015)

Fuel Mix for Electric Generation by Region

The fuels used for electric generation vary widely across the country. As shown in Exhibit 2.25, coal dominates the fuel mix in the Mountain, West North Central, and East North Central (including Michigan) regions. Natural gas is the primary fuel source in New England, West South Central, and in the Pacific Contiguous regions. The largest share of nuclear generation is in the Middle Atlantic (U.S. EIA March 25, 2015). A map explaining which states are in which regions is included in Appendix D.

EXHIBIT 2.25. Fuel Mix for Electric Generation, 2013

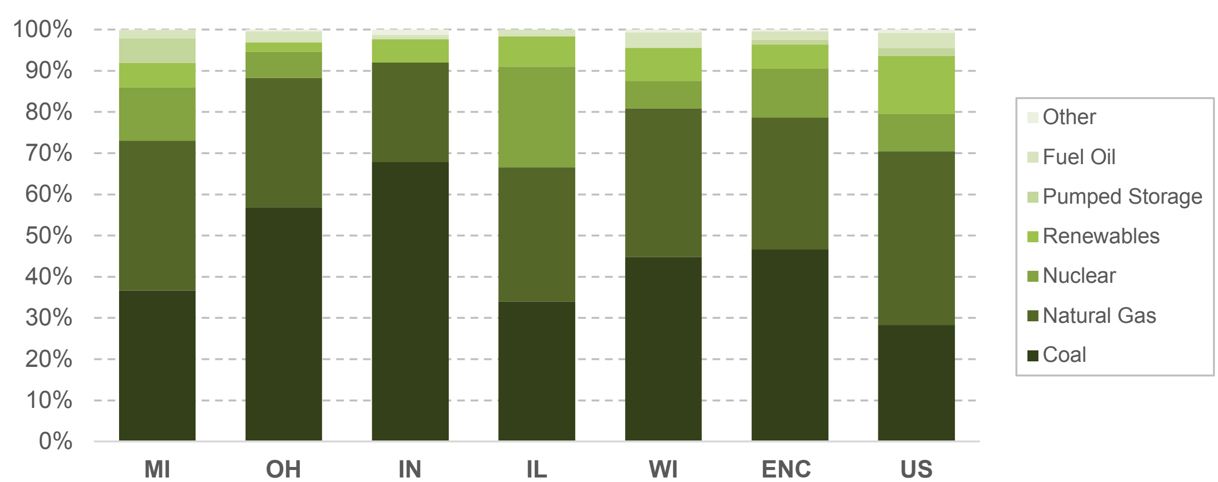


SOURCE: U.S. EIA. February 17, 2015. *Form 860*. Available at: http://www.eia.gov/totalenergy/data/monthly/. (accessed 3/21/2015

East North Central States

The U.S. Census Bureau groups Indiana, Illinois, Ohio, Wisconsin, and Michigan together in the East North Central (ENC) region. As shown in Exhibit 2.26, the regional average fuel mix is very similar to Michigan's generation portfolio, but the ENC region has more coal resources than the national average.

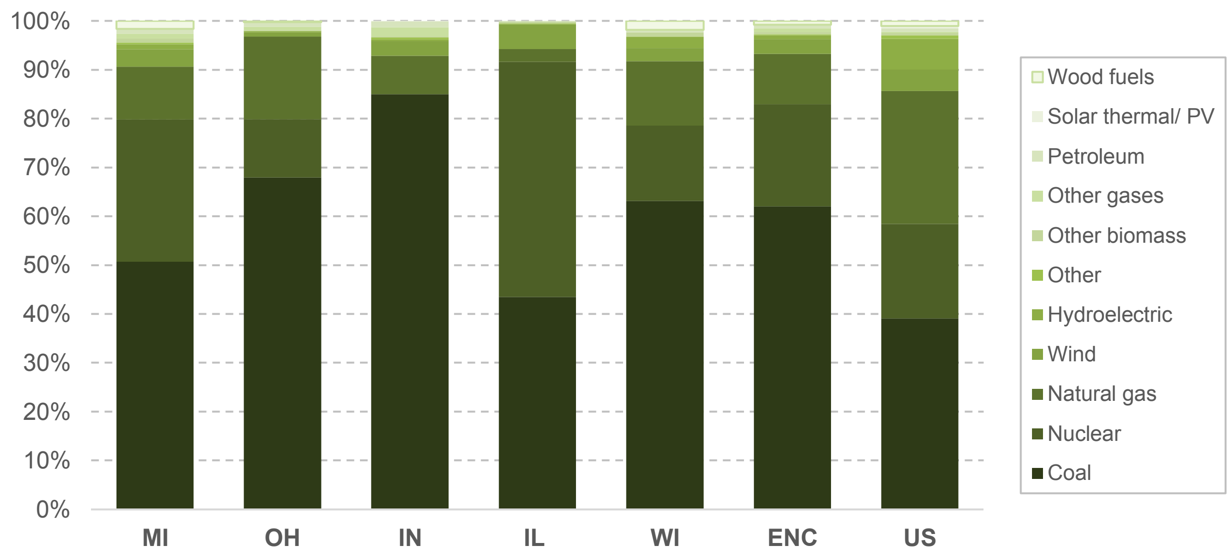
EXHIBIT 2.26. Generation Nameplate Capacity by Fuel Type, 2013



SOURCE: U.S. EIA. February 17, 2015. Form 860. Available at: http://www.eia.gov/totalenergy/data/monthly/. (accessed 3/21/2015)

The fuel mix for electricity generated looks very similar to the capacity fuel mix, as shown in Exhibit 2.27. Coal and nuclear facilities make up the bulk of generation in these states.

EXHIBIT 2.27. Comparison of Annual Net Generation by Fuel Type (GWhs)



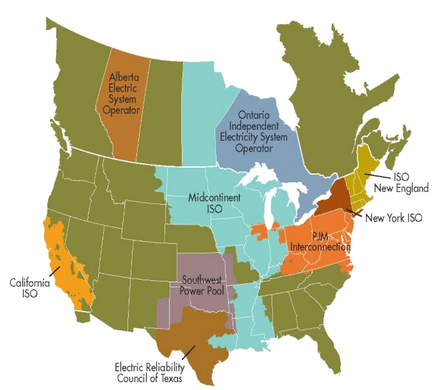
SOURCE: U.S. EIA. March 25, 2015. *Form EIA-923*. Available at: http://www.eia.gov/electricity/data/eia923/. (accessed 4/4/2015)

Regional Transmission Organization

Since Michigan's electric providers belong to RTOs, the electricity generated in Michigan is not exclusively consumed in the state. Instead, RTOs dispatch electric generation across their footprint to achieve the most cost-effective and reliable supply of energy. This means that generation from outside of Michigan can be consumed in the state; thus, it is useful to look at the fuel mix for these regional entities when examining electric resources.

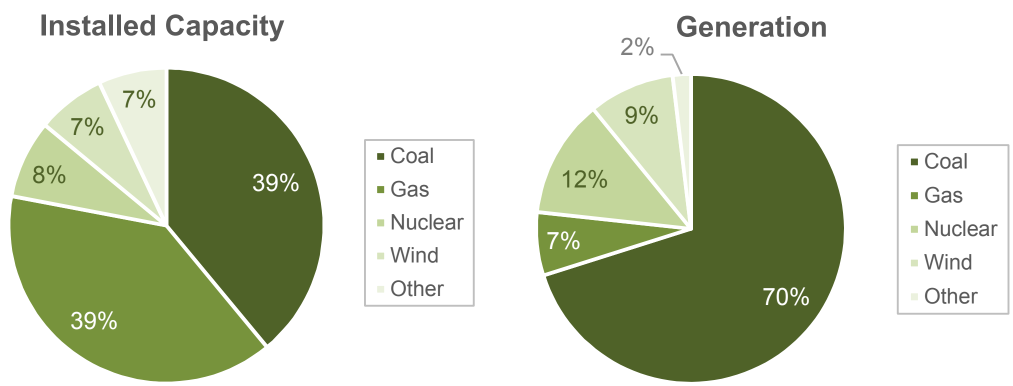
As shown in Exhibit 2.28, there are two RTOs with service territory in Michigan: MISO and PJM. Exhibits 2.29 and 2.30 show the installed generating capacity and generation by fuel source for the MISO and PJM RTOs.

EXHIBIT 2.28. Regional Transmission Organization Service Territories



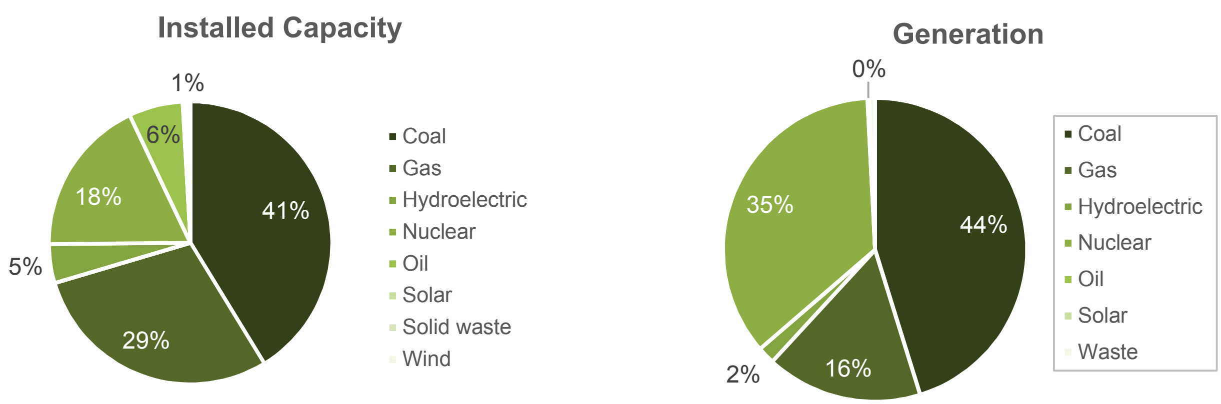
SOURCE: Sustainable FERC Project, n.d., *ISO RTO Operating Regions*. Available at http://sustainableferc.org/wp-content/uploads/2013/10/ISO-RTO-Operating-Regions.jpg. (accessed 5/5/15)

EXHIBIT 2.29. MISO Installed Capacity (2014) and Generation (2013) by Fuel Type



NOTE: Other is comprised of hydro, oil, other, pet coke, and waste. Gas includes units with gas and gas/oil fuel type.
SOURCE: MISO. June 2014. *MISO 2013 Annual Market Assessment Report.* Available at: https://www.misoenergy.org/Library/Repository/Report/Annual%20Market%20Report/2013%20Annual%20Market%20Assessment%20Report.pdf. (accessed 3/21/2015)

EXHIBIT 2.30. PJM Installed Capacity and Generation by Fuel Type, 2013

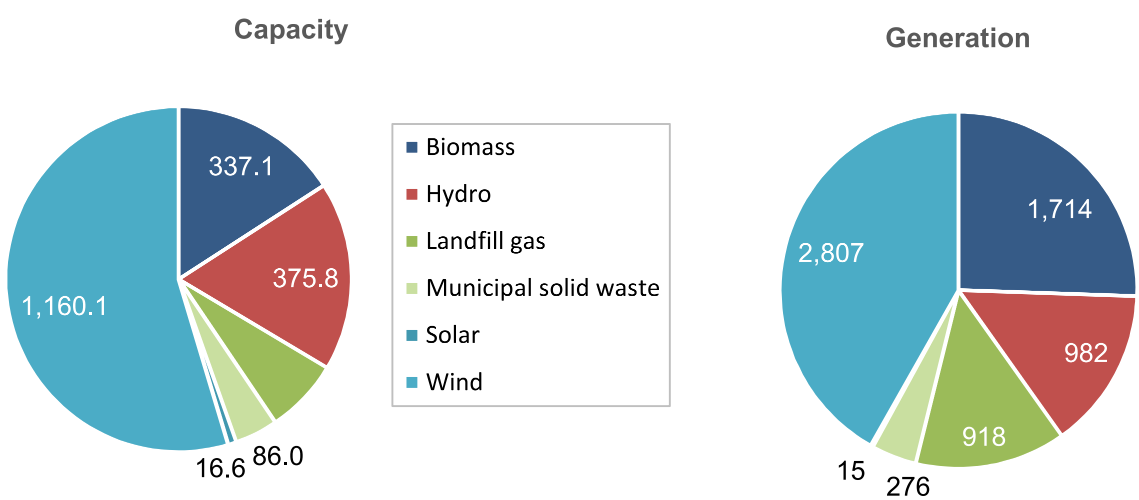


SOURCE: Monitoring Analytics. 2014. *2013 State of the Market Report for PJM.* Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-press-briefing.pdf. (accessed 3/21/2015)

Renewable Generation

Since Michigan adopted a renewable portfolio standard in 2008, there has been significant investment in renewable generation in the state. As shown in Exhibit 2.31, nearly 1,500 MWs of new renewable generation has been added since the standard was put in place. The majority of this added capacity is from onshore wind capacity (MPSC 2015). Michigan's other renewable energy sources include more than 100 hydroelectric facilities, methane capture landfill gas facilities, anaerobic digesters, and wood waste facilities. A map of PA 295 generating projects is available in Appendix E. Overall, renewable resources contribute about 7 percent to the state's net electricity generation (MPSC 2015).

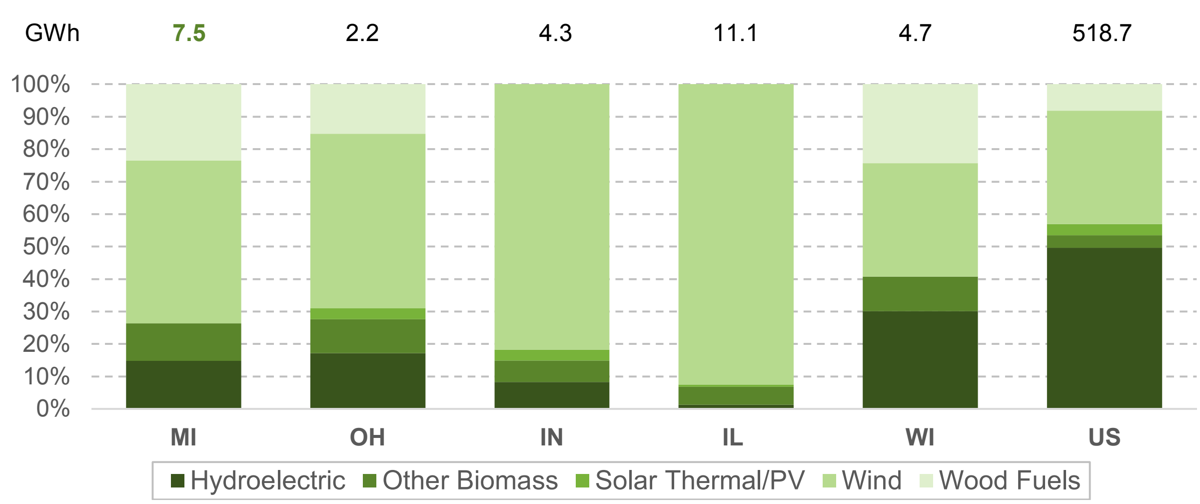
EXHIBIT 2.31. Renewable Capacity (MW) and Generation (GWh), 2013



SOURCE: Michigan Renewable Energy Certification System (MIRECS).n.d. *MIRECS Projects.* Available at: https://portal2.mirecs.org/myModule/rpt/myrpt.asp?r=111 (accessed 3/21/15)

As shown in Exhibit 2.32, renewable energy produced 7.5 gigawatt hours (GWhs) of electricity in 2013. Compared to neighboring states, only Illinois generated more electricity from renewables than Michigan. Onshore wind energy is the most common renewable energy resource for ENC states (U.S. EIA March 25, 2015). A map showing the location of renewable energy projects in Michigan, is available in Appendix E.

EXHIBIT 2.32. Comparison of Annual Net Generation of Renewables by Fuel Type



SOURCE: U.S. EIA. March 25, 2015. *Form EIA-923*. Available at: http://www.eia.gov/electricity/data/eia923/. (accessed 4/4/15)

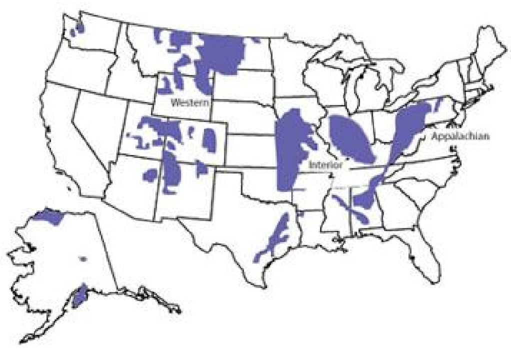
Fuel Supply

Access to a diverse, cost-effective supply of fuel resources is vital to ensuring reliable and affordable electricity. Fuels used for electricity production come from a variety of sources. Many of them must be transported from the source to a processing facility and on to the end user. Energy delivery relies on a series of interactions; when the system becomes congested or breaks down, customers face the prospect of increased prices or reduced service quality.

Coal Supply and Delivery

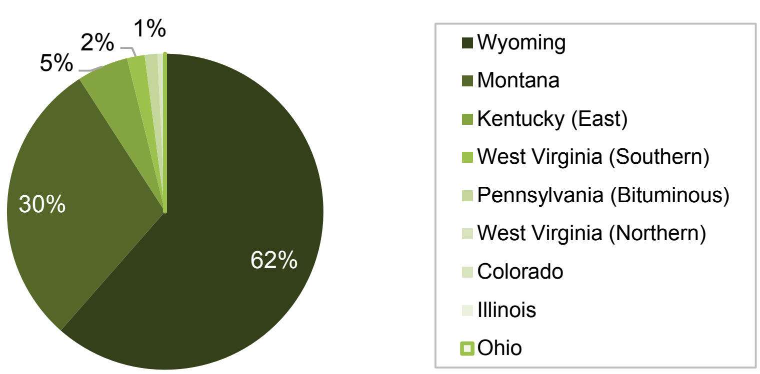
Coal is the primary energy source for production of electricity in Michigan. Since Michigan doesn't have any sizable coal reserves or active coal production, electric producers have to bring in coal from other states. As shown in Exhibit 2.33, there are three main regional coal deposits in the United States. Despite the proximity of coal deposits in the interior region and Appalachia, the majority of the coal that Michigan consumes comes from the western producers, in Wyoming and Montana, as shown in Exhibit 2.34 (U.S. EIA December 2014).

EXHIBIT 2.33. Coal Resource Regions



SOURCE: U.S. EIA. January 21, 2015. *U.S. Coal Reserves.* Available at: http://www.eia.gov/coal/reserves/. (accessed 4/6/15)

EXHIBIT 2.34. State of Origin for Coal Delivered to Electric Power Sector in Michigan, 2013



SOURCE: U.S. EIA. December 12, 2014. *Annual Coal Distribution Report*. Available at: http://www.eia.gov/coal/distribution/annual/. (accessed 3/21/15)

Compared to other energy sources, coal has the advantage of being easily stored at power plants. Unlike nuclear fuel, it does not require additional physical security, and unlike natural gas, it can be stored onsite without additional infrastructure. Power plants typically maintain a stockpile of coal that allows them to operate without interruption between deliveries or during periods of increased demand. Even so, supplies can be strained under certain circumstances. A recent example occurred during the "polar vortex" in the winter of 2013. Railroads normally move nearly 70 percent of coal shipments in the United States (AAR 2014) with great reliability, but during that winter, the expected shipments of coal from western producers were delayed—due to extreme cold weather and previously occurring increased demand for limited railroad capacity from competing commodities. The delayed coal shipments caused operators throughout the Midwest to burn through their reserves (and in some cases, nearly run out) of fuel (Shaffer 2014).

The challenges that electric producers and customers faced during that period of extreme winter weather generated outrage among producers and elected officials, who have called on federal regulators to address the problem (Johnson 2014). On December 30, 2014, the U.S. Surface Transportation Board directed the BNSF Railway—the primary rail service provider for western coal shipments—to develop contingency plans designed to address coal shortages at Midwest power plants (U.S. STB 2014).

Natural Gas Supply and Storage

The electric power sector is the largest consumer of natural gas. In 2013, 11 percent of Michigan's electricity was generated from natural gas, as illustrated in Exhibit 2.35 below (U.S. EIA March 25, 2015). Unlike coal, which can be stored easily on site at power plants, natural gas is typically delivered as it is consumed. Natural gas delivery is coordinated across more than 200,000 miles of interstate pipelines that connect producers, processors, and end users (U.S. DOE 2015). An overview of interstate natural gas pipeline capacity and locations is available in Appendix G.

EXHIBIT 2.35. Natural Gas Delivery, Consumption, Production, and Price, Michigan (MMcf)

	2009	2010	2011	2012	2013
Interstate receipts	1,862,322	1,860,721	1,906,908	1,805,044	1,662,101
Interstate deliveries	116,961	115,066	56,903	150,868	269,123
Dry production	69,803	55,316	70,266	63,357	58,806
Consumption	735,340	746,748	776,466	790,642	813,300
Consumption by electric power sector	83,805	113,245	112,783	181,235	109,007
Electricity generated from natural gas (MWhs)	8,419,551	12,249,262	12,982,054	21,748,358	12,341,392
Natural gas price to electric power sector (dollars/thousand cubic feet)	$4.55	$4.97	$4.76	$3.21	$4.57

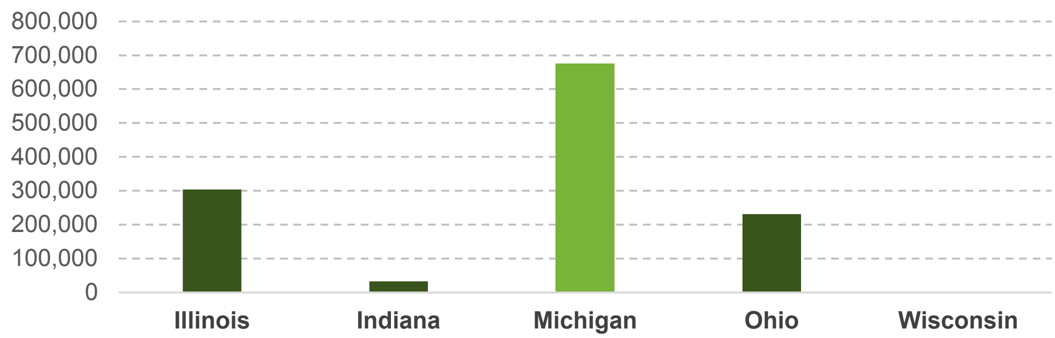
SOURCES: U.S. EIA. March 31, 2015. *Natural Gas Annual Supply & Disposition by State*. Available at: http://www.eia.gov/dnav/ng/ng_sum_snd_a_EPG0_FPD_Mmcf_a.htm. (accessed 4/12/15)

Natural gas pipelines have limited transport capacity—on average, only 54 percent of pipeline capacity is used—and in circumstances when demand is extremely high or a pipeline fails, congestion can occur (U.S. DOE 2015). During the "polar vortex" in 2013, when extreme cold caused demand for natural gas to spike, existing pipeline infrastructure in the Northeastern United States had trouble keeping up with demand, which led to a sharp rise in energy prices (Edwards 2014). A complete inventory of Michigan's interstate pipelines is available in Appendix F.

Michigan depends on interstate pipelines for approximately 80 percent of its natural gas supply, but because there is abundant underground storage capacity, the state can limit its exposure to supply issues. As displayed in Exhibit 2.36, Michigan has more than 10 percent of the nation's underground natural gas storage capacity—the most of any state. For an overview of Michigan's storage capacity and locations, see Appendix G. Underground storage fields allow energy providers to buy and store natural gas during the summer months, when demand is lower. Exhibits 2.37 and 2.38 show how natural gas storage fields were utilized in 2014 (U.S. EIA 2007). The stored natural gas can then be withdrawn during seasonal heating months, when demand is higher. This practice helps suppliers avoid potential transmission constraints or seasonal price variations (MPSC May 15, 2014). A summary of annual natural gas storage injections and withdrawals is displayed in Exhibit 2.37.

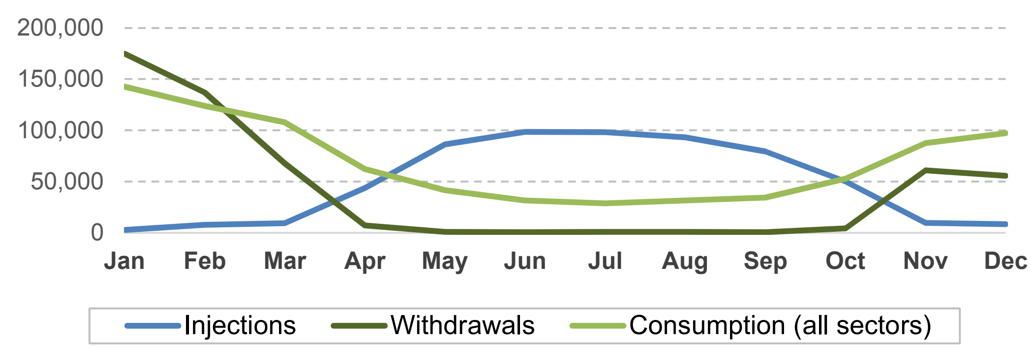
The U.S. Department of Energy recently released a report detailing its expectations for natural gas supply given current trends in electric generation. Despite projections that the natural gas share of electric generation will grow substantially through 2040, the U.S. DOE predicts that infrastructure investment will be modest. According to the U.S. DOE findings, increased natural gas consumption can be accommodated by expanding capacity of current pipelines, utilizing existing capacity more fully, or shifting the flow of natural gas (U.S. DOE 2015).

EXHIBIT 2.36. Working Underground Natural Gas Storage Capacity by State, 2013 (Mmcfs)



SOURCE: U.S. EIA. March 31, 2015. *Underground Storage Capacity.* Available at: http://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SAC_Mmcf_a.htm. (accessed 4/12/15)

EXHIBIT 2.37. Natural Gas Underground Storage in Michigan, 2014 (Mmcfs)



SOURCE: U.S. EIA. March 31, 2015. *Natural Gas Annual Supply & Disposition by State.* Available at: http://www.eia.gov/dnav/ng/ng_sum_snd_a_EPG0_FPD_Mmcf_a.htm. (accessed 4/12/15)

EXHIBIT 2.38. Natural Gas Storage, Michigan (MMcf)

	2009	2010	2011	2012	2013	2014
Injections into storage	462,022	393,814	457,240	307,948	414,172	587,171
Withdrawals from storage	393,748	434,764	385,364	323,187	551,992	511,739

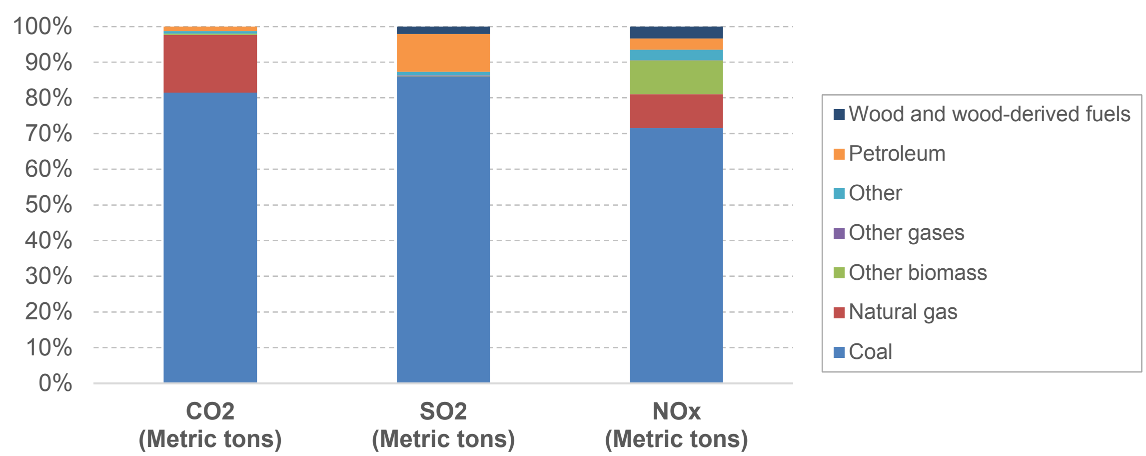
SOURCE: U.S. EIA. March 31, 2015. *Underground Storage Capacity.* Available at: http://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SAC_Mmcf_a.htm. (accessed 4/12/15)

Environmental Performance

Nearly 70 percent of the nation's electricity is generated by burning fossil fuels, mainly coal and natural gas. While it generates energy vital to modern day life, combusting fossil fuels also produces harmful emissions that impact the environment. All sources of electricity have some impact on the environment, but air pollutants from fossil-fueled generation are of particular concern. According to the U.S. Environmental Protection Agency (EPA), the electric power industry produces 32 percent of all greenhouse gas emissions including 65 percent of sulfur dioxide (SO2) and 16 percent of nitrogen oxides (NOx) emissions (U.S EPA April 15, 2014).

As shown in Exhibit 2.39, coal is the source of most of the carbon dioxide (CO2), SO2, and NOx emitted in Michigan. Coal-fired units produced 90 times as much SO2, twice as much CO2, and over five times as much NOx per unit of electricity compared with natural gas units (GAO April 18, 2012).

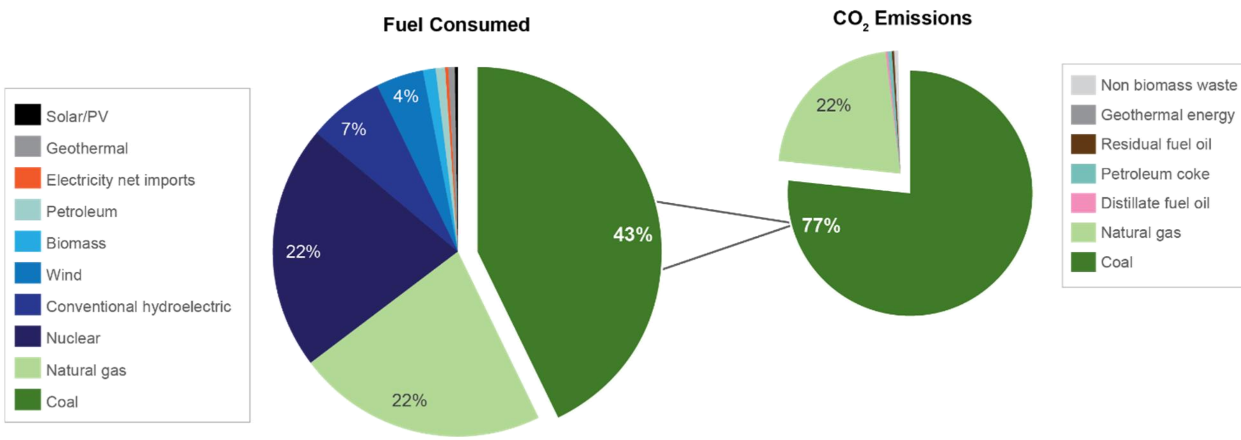
EXHIBIT 2.39. Percentage of Electric Power Industry Emissions by Fuel Source, Michigan, 2012



SOURCE: U.S. EIA. March 25, 2015. *U.S. electric power industry estimated emissions by state, back to 1990 (EIA-767 and EIA-906)*. Available at: http://www.eia.gov/electricity/data/state/emission_annual.xls (accessed 4/4/15)

Despite only supplying 43 percent of the total fuel for the electric power sector, coal is responsible for 77 percent of all CO2 emissions as shown in Exhibit 2.40.

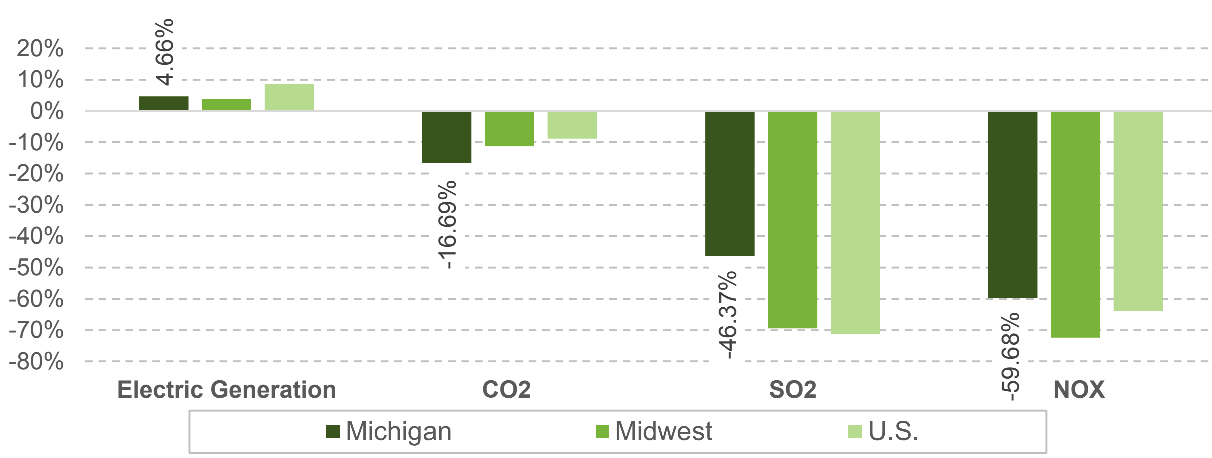
EXHIBIT 2.40. Fuel Consumed by the Electric Power Industry and CO2 Emissions from the Electric Power Industry by Fuel Source, U.S., 2013



SOURCE: U.S. EIA. March 25, 2015. *Form EIA-923*. Available at: http://www.eia.gov/electricity/data/eia923/. (accessed 4/4/15) and U.S. EIA. March 26, 2015. *Monthly Energy Review*. Available at: http://www.eia.gov/totalenergy/data/monthly/. (accessed 4/4/15)

As shown in Exhibit 2.41, overall air pollution has decreased dramatically since 1990 (U.S. EPA February 2012). Increasingly stringent regulations for electric generating units have helped to drive down emissions across the nation and the Midwest. Since 1999, even though total electric generation has gone up, Michigan's electric generators have reduced CO2, SO2, and NOx emissions at rates similar to the national and region average.

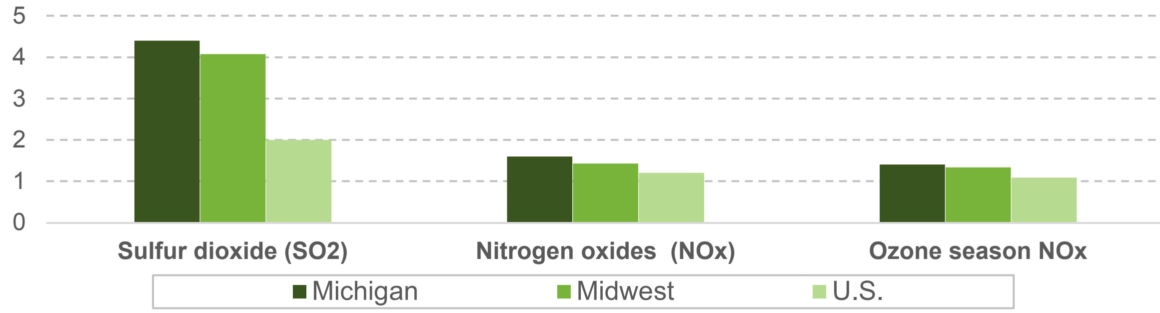
EXHIBIT 2.41. Percent Change in Electric Generation (MWhs) and Emissions (thousand metric tons), 1999–2012



SOURCE: U.S. EIA. March 19, 2015. *Emissions from Energy Consumption at Power Plants and Combined-Heat-and-Power-Plants.* Available at: http://www.eia.gov/electricity/annual/html/epa_09_05.html. (accessed 4/7/15)

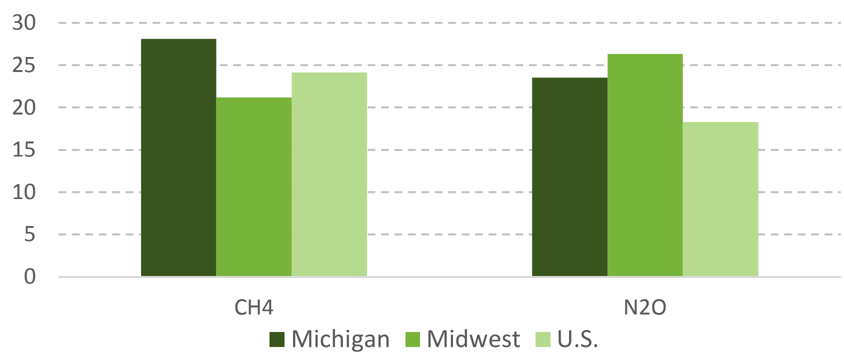
A electric generator's emissions rate is the amount of air emissions generated from the production of a unit of electricity, commonly displayed as pounds per megawatt hour. Because different fuels produce different levels of emissions, a state's emissions rate is largely dependent on its generation fuel mix. As shown in Exhibit 2.42, the emissions rate for electric generators in Michigan is similar to the regional average and above the national average (U.S. EPA February 2014). An inventory of emissions from the state's electric generators is available in Appendix H.

EXHIBIT 2.42. Total Emissions Rates for Sulfur Dioxide, Nitrogen Oxides and Ozone (lbs/MWh)



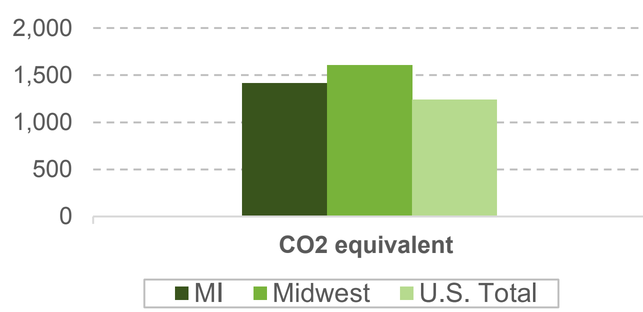
NOTE: Ozone season is from May 1 to September 30, when ozone conditions are of greatest concern.
SOURCE: U.S. EPA. February 24, 2014. *eGRID.* Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. (accessed 3/21/15)

Total Emissions Rate for Methane (CH4) and Nitrous Oxide (N_2O),and Carbon Dioxide Equivalent ($CO2_e$) (lbs/GWh)



SOURCE: U.S. EPA. February 24, 2014. *eGRID.* Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. (accessed 3/21/15)

Total Emissions Rate for Carbon Dioxide Equivalent ($CO2_e$) (lbs/MWh)



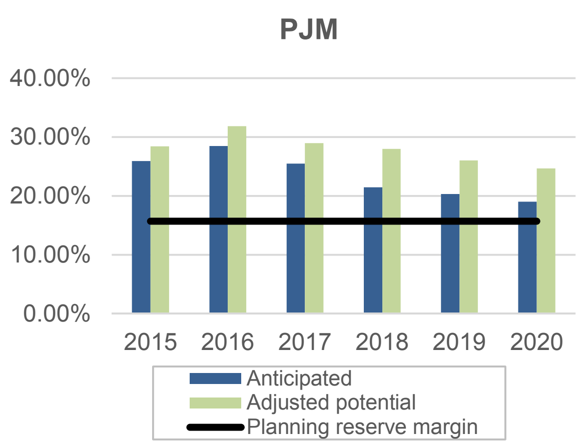
SOURCE: U.S. EPA. February 24, 2014. *eGRID.* Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. (accessed 3/21/15)

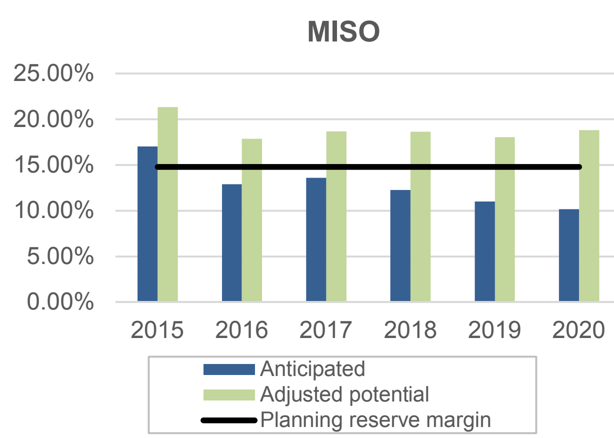
Resource Adequacy

The North American Electric Reliability Corporation (NERC) sets reliability standards for the electric grid across the U.S. and Canada. States retain jurisdiction to enforce resource adequacy standards over regulated utilities. Notwithstanding, with the advent of regional markets in recent years, RTOs have begun coordinating resource adequacy planning. Resource adequacy standards are important because in order to ensure a reliable supply of electricity, providers need to maintain sufficient resources to respond to increased consumer demand, unexpected generation outages, and numerous other factors that impact their ability to deliver electricity. RTOs calculate their anticipated peak energy demand for the coming years[10] and based on anticipated needs establish requirements for electric suppliers. This requires, among other things, that the amount of resources exceeds customer demand by an adequate margin. A complete discussion of RTO operations is available in Appendix I. These planning reserve margin requirements (PRMR) are designed to make sure that resources are available at all times and through a variety of circumstances.

As shown in Exhibit 2.43, in MISO, the PRMR for 2014–2015 is set at 14.8 percent. MISO projects that the reserve margin will drop below the 14.8 percent requirement by 2016. The primary driver of MISO's deficiency is the retirement of power plants in the RTO (NERC 2014). PJM's PRMR for the same time period is 15.7 percent. PJM is expected to have an adequate reserve margin through the year 2020 (NERC 2014).

EXHIBIT 2.43. Planning Reserve Margins, PJM and MISO





SOURCE: North American Electric Reliability Corporation. November 2014. *2014 Long-Term Reliability Assessment*. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf. (accessed on 12/1/14)

Resource Adequacy Self-assessments

Since 1998, the MPSC has conducted annual investigations into the ability of the regulated utilities in Michigan to secure adequate resources to meet customer demand in their respective service territories. In subsequent years, the commission has expanded the scope of these investigations to include, among other things, transmission considerations, the effect of retail open access (ROA) programs, wholesale market issues, and the interconnection of merchant generation. In Case No. U-14087, the commission again expanded its investigation to include all regulated utilities, including member-regulated cooperatives. In its December 2013 order in Case No. U-17523, the commission found that it should conduct a similar investigation that would span the three-year period of 2014 through 2016, due to the

[10] In some RTOs, such as MISO, the demand forecasts are provided by the load serving entities for this purpose and compiled by the RTO.

expected retirement of older generating units in the state associated with the implementation of new air quality requirements.

The commission now finds it appropriate to further extend the horizon to a five-year period, primarily due to the information submitted in U-17523, and the prospect of significant capacity shortfalls in Michigan beginning as early as 2016. The commission is interested in maintaining a forward-looking picture of the capacity position of the state and proactively helping to address any potential issues that can be reasonably foreseen (MPSC Case No. U-17751 December 4, 2014).

Expected capacity shortfalls increase the probability of electric outages resulting from potential shortages during peak load periods, extreme weather, equipment failures, or other system disruptions. Therefore, this case intends to provide a meaningful and transparent picture of the supply outlook and associated risks for the state as a whole and for individual providers. Toward that end, the commission directed staff to develop and distribute to load serving entities (LSEs) a uniformly formatted table with fields to populate with key data points. Staff is currently evaluating the submittals filed by the LSEs in U-17751 (MPSC March 23, 2015).

Utility reliability plans filed in MPSC Case No. U-17751 show that Michigan energy providers are planning to meet their PRMR through a variety of energy resources, including owned generation, qualifying demand response programs, power purchase agreements, and other capacity contracts. Five electric utilities—Consumers, DTE, I&M, Upper Peninsula Power Co. (UPPCo), and Wolverine Power Cooperative—collectively serve more than 91 percent of Michigan customers as shown in Exhibit 2.44. The combined reliability plans for these utilities show that overall, suppliers plan to have sufficient resources through 2020 (see Exhibit 2.45). Of these five utilities, only plans filed by DTE, I&M, and UPPCo show a projected capacity shortage during the five-year planning period. Their filings explain they plan to procure required resources through capacity auctions or other contracts for capacity. A summary of reliability plans for these five utilities can be found in Appendix J.

EXHIBIT 2.44. Number of Customers Served by Five Utilities

Customers Served	Number of Customers Served	Percent of Customers Served
DTE Energy	2,134,569	44.93%
Consumers Energy	1,790,148	37.68%
Wolverine Power Cooperative*	249,575	5.25%
Indiana Michigan Power Company	127,908	2.69%
Upper Peninsula Power Company	52,035	1.10%
Total for Five Companies	**4,354,235**	**91.65%**

* Includes Cherryland, Great Lakes, HomeWorks, Midwest Energy Cooperative (Midwest), Presque Isle, Wolverine Power Marketing Cooperative, Inc. (WPMC) and Spartan Renewable Energy, Inc. (Spartan)
SOURCE: U.S. EIA. March 23, 2015. *Electric Power Annual*. Available at:http://www.eia.gov/electricity/sales_revenue_price/pdf/table10.pdf (accessed 4/30/15)

EXHIBIT 2.45. Electric Reliability Supply Plans for Five Utilities, Combined

Planning Year	2015–2016	2016–2017	2017–2018	2018–2019	2019–2020
Total Planning Reserve Margin, (MW)	24,872	24,796	24,872	24,816	24,824
Total Planning Resources, (MW)	24,916	25,330	25,003	25,077	25,122
Surplus/(Shortfall), (MW)	44	534	131	261	298

NOTE: The total planning reserve margin and planning resources shown in this exhibit do not consider load or resources for other utilities or alternative electric suppliers, so they are not representative of the overall supply position of the state. Moreover, information for I&M is included in this summary, but not part of MISO footprint; therefore, it would be subject to PJM reserve margin requirements.

SOURCE: MPSC. December 4, 2014. Plans Filed in Case No. U-17751.Available at: http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=17751&submit.x=16&submit.y=9 (accessed 5/4/15)

Supply and Demand Efficiency

Generation Efficiency

The measure of efficiency for electrical generating unit is its heat rate. Heat rate is the amount of energy inputs—measured in British thermal units (BTUs)—a plant uses to generate one kilowatt hour (kWh) of electricity (U.S. EIA April 2015). Michigan's electric generation portfolio is diverse and varies by vintage. Facilities were built in distinct phases that reflect historical, economic, and policy decisions as well as technology changes over the past 60 years.

Michigan's baseload coal plants were built from the 1950s to the 1980s. Coal-generating facilities are designed to operate most efficiently at full power. These units have typically been relied on to supply round-the-clock electricity needs. On average, heat rate performance has declined in baseload coal plants since the 1960s. Two main contributors to declining efficiency of baseload coal plants were the increased production associated with new nuclear facilities[11] constructed during the 1960s and 1970s and the EPA regulations established following the passage of the Clean Air Act. The introduction of baseload nuclear facilities resulted in greater variation in the dispatch of coal units. More startups, shutdowns, and alteration of load caused coal units to operate below full power. This reduced their heat rate performance and capacity factors (U.S. EIA March 25, 2015). Likewise, EPA rules began to require various types of pollution control equipment be installed on these coal plants that ultimately reduced the net output of a plant. The average operating heat rate for coal generation in 2012 is 10,498 BTUs/kWh, a 1 percent increase since 2002 (U.S. EIA March 25, 2015). Recent studies have highlighted several measures that can improve the overall efficiency for coal-fired power plants. Although many of these measures have high costs, studies indicate heat rates could improve by 1.2 to 4 percent through the installation of efficient air heaters, turbine upgrades, pump upgrades, and combustion optimization (Sargent and Lundy 2009, p 41-43).

Driven by lower prices, availability of pipeline infrastructure, and ramp capability[12], natural gas plants have been the main source of generating capacity built in Michigan since the 1990s. Continued technological improvements in natural gas generation have allow for increased efficiencies through improved turbine designs and the move from a simple cycle design to a combined cycle design by converting otherwise wasted heat to mechanical energy. Since 2002, the average efficiency of a natural gas generating unit has increased by 15 percent, the average heat rate in 2012 was approximately 8,039 BTUs/kWh. Some recent designs have exhibited the potential to reach a heat rate as low as 6,700 BTUs/kWh, depending upon operating conditions (MPSC July 2013).

The efficiency of renewable resources is not discussed in terms of heat rate because renewables do not rely on heat energy. Instead, the efficiency of renewables is measured by determining its capacity factor. The National Renewable Energy Laboratory (NREL) defines capacity factor as "a measure of how much energy is produced by a plant compared to its maximum output. It is measured as a percentage, generally by dividing the total energy produced during some period of time by the amount of energy it would have produced if it ran at full output over that period of time" (NREL July 2012). Since many renewable resources are dependent on atmospheric or environmental conditions, their generation is intermittent. Wind generation has grown considerably since Michigan adopted its renewable portfolio standard (RPS). Wind generation technology has grown considerably in the last couple of years. Onshore wind generation has a capacity factor, or operational uptime, of 30 to 39 percent (U.S. EIA April 27, 2015). Taller towers and larger blade diameters allow for much higher capacity factors and optimized operating characteristics. Based on third-party and electric provider analysis, Michigan wind farms that

[11] Average nuclear facility heat rates remain virtually unchanged since 2002 and are approximately 10,460 Btu/kWh.
[12] Ramp rate refers to how quickly a plant can begin generating electricity in response to increased demand. Ramp rates vary based on fuel source and technology.

utilize these new technologies are anticipated to produce capacity factors well over 40 percent (MPSC November 4, 2013).

Michigan also is home to the Ludington Pumped Storage Plant—a unique generating resource that pumps water uphill to a reservoir during low-demand times, then uses that same water running downhill to generate electricity during high-demand times. This facility basically acts like a large battery storage device to provide system stability and pairs well with the nearby wind generation. Due to the availability of more efficient turbines, the facility is currently undertaking an upgrade of all six turbines to more efficient models, which will increase the generating capacity by approximately 15 percent (Consumers Energy).

Distribution Efficiency

Electricity is lost as it is transferred from the point of generation across power lines to the ultimate consumer. On average, 6 percent of all electricity generated is wasted through line losses (U.S. EIA May 7, 2014 a). The transmission systems accounts for between 2 to 3 percent of line losses, depending upon the system configuration. The remaining line losses can be attributed to the distribution system. Distribution line losses depend on variables like the vintage of the equipment, the distance between customers, and the distance between generation and the customer area. The cost associated with line losses varies depending on when energy is being produced and by what resources. More costly generators are used during peak demand periods, resulting in more costly system losses. Electric utilities across the nation are exploring ways to improve efficiency by reducing line losses. Possible ways to increase the efficiency of the distribution system include the reduction of losses at transformers, reduction of losses in cable wires, and maintaining tight control of voltage and current fluctuations (ABB N.d. and NEMA N.d.). Gains in efficiency can be made by addressing and replacing older or obsolete transformers, installing capacitors in strategic locations, replacing old conductors, and overlaying digital technology to optimize power flow (Dominion 2012).

Michigan utilities are beginning to leverage digital technology on the distribution grid. The installation of digital meters has started in some areas (MPSC October 2010, and MPSC 2012). Digital meters have the capability to monitor power quality and provide grid reliability data by identifying system outages. Digital meters working in conjunction with monitoring and control equipment have the potential to help recover from momentary outages. By using voltage conservation[13], utilities can maintain optimum power flow along the distribution grid, resulting in a reduction of line losses and energy needed at peak times. As utilities continue to upgrade equipment, obsolete equipment will likely be replaced with efficient equipment and integrated digital technology. However, it is important to weigh the cost of reliability and the savings in increased efficiency against the added energy required to operate new digital equipment.

Distribution Resiliency and System Hardening

The importance of system hardening and resiliency is most apparent during extreme weather events. As the distribution infrastructure ages, it is more vulnerable to increased damaged from extreme weather and extended outage periods (MPSC May 30, 2014). In order to maintain the high level of reliability that customers expect, utilities should take measures to harden the distribution system against extreme damage and increase the system's resiliency to quickly recover.

The initial step in designing a plan to address system hardening and resiliency is to understand and document the causes of outages that occur throughout the system. Collecting data following a storm or major weather event is one way utilities can work towards improving distribution networks (Quanta 2010). Accurate data and documentation during and after power restoration is critical in understanding the true weaknesses of a distribution system. Storm data is critical in establishing reliability goals and metrics, which will continue to be used as improvements are made to measure system performance and customer benefit. Detailed outage data is also needed to provide a clear understanding of the causes and types of outages that occur and identify potential maintenance, capital investment, and asset management projects that support system reliability.

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[13] Dominion's demonstration shows an average of 2.8 percent reduction in annual energy.

Demand Side Efficiency

Energy Savings

The energy optimization (EO) targets, established by PA 295, have led to significant investment in reducing energy waste and promoting efficient energy consumption. As shown in Exhibit 2.46, EO programs have saved more than 4 million MWhs of electricity and 15.2 thousand cubic feet (Mcf) of natural gas since inception. While some utilities initially struggled to meet targets, on the whole, utilities have exceeded them.

EXHIBIT 2.46. EO Programs Combined Annual Energy Savings

	Electric (MWh)	Natural Gas (Mcf)
2009	375,643	647,463
2010	787,474	2,110,246
2011	1,000,437	3,836,008
2012	1,198,644	4,282,874
2013	1,301,241	4,412,441
	4,663,439	**15,289,032**

SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs*. Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf. (accessed 1/21/15)

Currently, 24 states have energy-efficiency resource standards (EERS) in place for electricity, and 15 states have a standard for gas savings. Standards vary from state to state; some standards are based on multiyear goals, and others are tied to spending levels. However, most standards are in the range of 0.7 to 2.5 percent for electricity and 0.3 to 2 percent for gas (ACEEE 2015).

Energy Optimization Program Spending

As shown in Exhibit 2.47, total expenditures for EO programs from 2009–2013 total $907,253,030. Program costs must be approved by the MPSC. To be approved by the commission, costs must be reasonable and prudent, and earn a score of 1.0 or higher on the Utility Cost Test (UCT). For 2013, electric utility EO programs averaged a UCT score of 3.90, and gas utility customer-funded EO programs averaged a UCT score of 3.60. Total spending for EO programs, in 2015, is capped at 2 percent of a utility's average retail sales for the year two years prior. Most Michigan utilities are currently spending at or near this cap.

EXHIBIT 2.47. Total Expenditures for Michigan Utilities for EO Programs Since 2008

Year	Electric Expenditures	Natural Gas Expenditures	Totals
2009–2011	$256,964,741	$151,302,076	$408,266,817
2012	$159,539,215	$86,863,118	$246,402,333
2013	$168,160,945	$84,422,935	$252,583,880
Totals	**$584,664,901**	**$322,588,129**	**$907,253,030**

SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs*. Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf. (accessed 1/21/15)

Wisconsin and Indiana[14] are spending 0.67 percent and 1.02 percent, respectively, to achieve relatively similar targets to Michigan. Certain states that have had energy-efficiency programs in place for longer are spending more—Vermont and Massachusetts are spending 5.32 percent and 6.42 percent, respectively. In 2010, utilities in the United States spent a combined $3.95 billion on electric EO programs, and a combined $838 million on gas EO programs (LBNL 2013).

Demand Savings

Only Consumers and DTE are required to report demand savings from EO programs. Their reported savings were included in their annual EO reports, filed with the MPSC, and are shown below in Exhibit 2.48.

EXHIBIT 2.48. Demand Savings from EO Programs

Year	Consumers Energy	DTE Energy
2012	83,415 kW	80,060 kW
2013	60,188 kW	84,290 kW

SOURCE: Energy savings information reported for Consumers Energy in Cases No. U-17281 and U-17601 and for DTE Energy in Cases No. U-17282 and U-17601 can be accessed electronically at: https://efile.mpsc.state.mi.us/efile/index.htm

In February 2011, the Federal Energy Regulatory Commission (FERC) released a report on the assessment of demand response and advanced metering. FERC reported potential peak load reduction in megawatts. In 2010, Michigan's demand response potential total was 1,748 MWs.

Distributed Generation

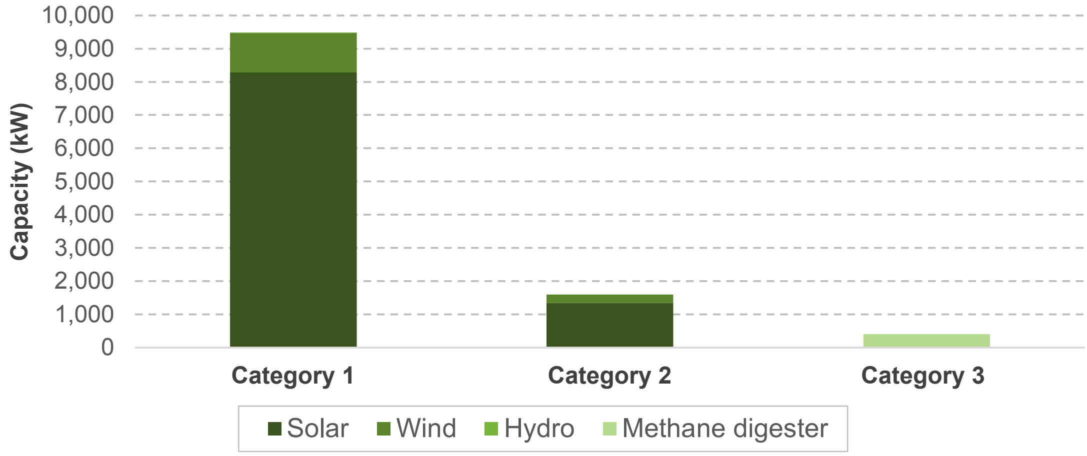
Customers of Michigan's rate-regulated utilities, cooperatives, and AESs are eligible to engage in net metering programs. These programs encourage the development of onsite renewable energy generation projects that offset some or all of a customer's electric energy needs and reduce their electric bills. Michigan allows net metering projects that fit into one of three categories (MPSC August 2014).

- Category 1: Projects up to 20 kW with inverter.
- Category 2: Projects greater than 20 kW and no larger than 150 kW and noninverter-based projects 20 kW and under.
- Category 3: Methane digester projects up to 550 kW.

Exhibit 2.49 shows the total capacity (kW) for each category.

[14] Indiana's Energy Efficiency Resource Standard was repealed in 2014 (DSIRE 2015).

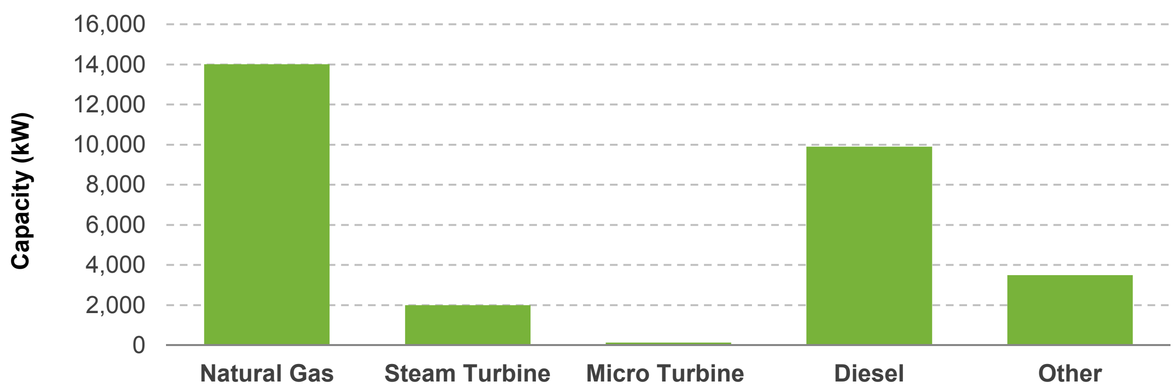
EXHIBIT 2.49. Net Metering Installed Capacity by Category (kW)



SOURCE: Michigan Public Service Commission. August 2014. *Net Metering and Solar Pilot Program Report for Calendar Year 2013.* Available at: http://www.michigan.gov/documents/mpsc/netmetering_report_2013_464591_7.pdf?20141113104742. (accessed on 11/13/14)

Based on data provided by DTE and Consumers, nonrenewable self-generation makes up approximately 29.5 MW of the companies' total system. These self-generation projects serve onsite load and are under 10 MWs in size. Exhibit 2.50 shows nonrenewable self-generation by fuel type.

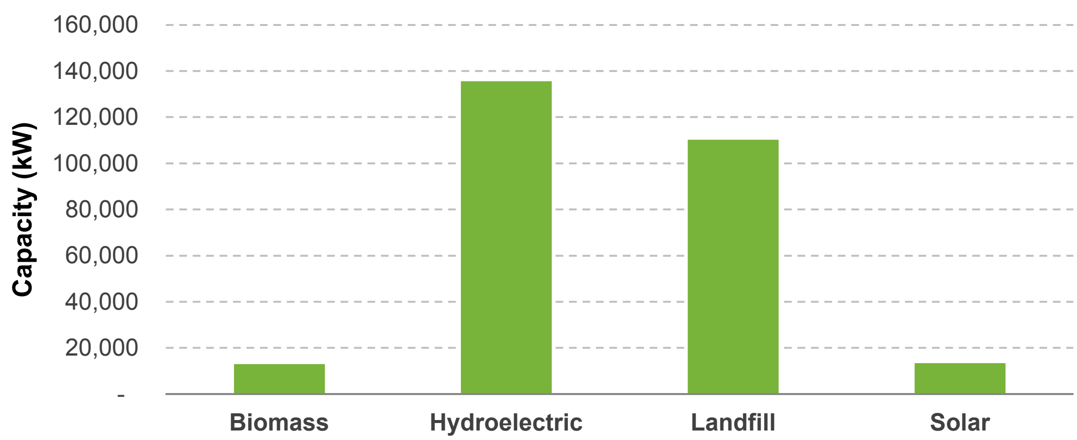
EXHIBIT 2.50. Nonrenewable Customer Self-generation (kW)



NOTE: The natural gas category includes some combined heat and power (CHP) production.
SOURCE: Information provided by Consumers and DTE.

Exhibit 2.51 is based on data from the Michigan Renewable Energy Certification System (MIRECS)—a statewide program established by the MPSC—which shows approximately 130 projects totaling 270 MWs of renewable distributed generation. Hydroelectric and landfill gas electric generation are the largest contributors to Michigan's renewable distributed generation. Many of these projects are likely independent power producers selling power under Public Utilities Renewable Policy Act (PURPA) contracts with utilities (not self-generation directly serving end-use customers).

EXHIBIT 2.51. Renewable Distributed Generation Resources (kW)



SOURCE: Michigan Renewable Energy Certification System (MIRECS).n.d. *MIRECS Projects.* Available at: https://portal2.mirecs.org/myModule/rpt/myrpt.asp?r=111 (accessed 3/21/15)

Section III.A. Current Regulatory Framework

A discussion about Michigan's current energy policy would not be complete without an overview of the regulatory structures that govern utility behavior. There are 85 electric providers operating in the state—eight investor-owned utilities, ten electric cooperatives, 41 municipal electric utilities, and 26 licensed alternative electric suppliers (AESs)—each provider is subject to some form of regulation by the MPSC (MPSC n.d). The following section provides an inventory of existing regulation and proceedings electric utilities are subject to. A brief overview of the regulations included in this section is also available in Appendix K.

UTILITY RATE CASES *(Michigan Common Law Act 3 of 1939, Section 460.6a; Amended Public Act 286 Sec. 10b [2008])*

The MPSC regulates the rates charged by public utilities, except municipally owned utilities, member-regulated cooperatives, and AESs. There are eight investor-owned utilities and three electric cooperatives with rates regulated by the commission. Michigan law specifies that a gas or electric utility shall not increase its rates and charges or alter, change, or amend any rate or rate schedules that increase the cost of service to its customers without first receiving commission approval (MCL 460.6a 2008). Rate cases are designed to set reasonable rates by analyzing utility company rate base investment, rate of return, operating expenses, depreciation, and taxes for the test period under review. Rates approved by the commission must be just and reasonable, taking into account the interests of both the utility and its customers. A utility can only file one rate case in a 12-month period, and cannot file a rate case if the commission has yet to issue a final order in a previous case.

To amend rates, a utility must file an application before the commission alleging that current revenues are insufficient due to changes in the costs of providing service. The rate case is a legal proceeding where the two basic issues of utility rates are decided; namely, (1) whether a utility company is to be allowed to change the rates for its service, and (2) if a change is allowed, the dollar amount and which groups of its customers will be affected (e.g., residential, commercial, or industrial). An administrative law judge (ALJ) presides over a rate case in much the same way a judge presides over a courtroom trial. After receiving and evaluating the testimony and evidence, the ALJ writes a proposal for decision (PFD), which sets forth his or her conclusions as to how the issues should be decided. The commission may accept, reject, or modify the PFD. In certain circumstances, in order to speed the resolution of a case, the commission will dispense with the PFD and read the record.

Public Act 286—signed into law in October 2008—established that a utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges. If the commission has not issued an order within 180 days of the filing of a complete application, the utility may implement up to the amount of the proposed annual rate request (i.e., self-implementation) through equal percentage increases or decreases applied to all base rates. If the amount a utility collects from customers exceeds the amount later approved by the commission, then the utility shall refund excess revenue with interest. For good cause, the commission may issue a temporary order preventing or delaying a utility from implementing its proposed rates or charges (MCL 460.6a 2008).

POWER SUPPLY COST RECOVERY *(Michigan Common Law Act 3 of 1939, Section 460.6j; Public Act 304 [1982]; Amended Public Act 81 [1987])*

As late as 1982, rate-regulated utilities were allowed to bill customers for increases in cost of fuel-related expenses without receiving prior approval from MPSC. Strong public criticism spawned two ballot proposals aimed at altering this practice. Proposal D's intent was to eliminate rate adjustment clauses and require all costs to be approved through general rate hearings. Proposal H's intent was to create separate limited issue hearings to approve rate adjustment clauses for the cost of fuel, purchased power, and purchased gas. At the same time the ballot initiatives were underway, the legislature was working on what became Public Act 304 of 1982. Both proposals were adopted by voters—meaning there were three different solutions to the same problem. The Michigan Supreme Court determined that Proposal H prevailed over Proposal D, and was compatible with Act 304 (Michigan State Chamber of Commerce v. State of Michigan, 417 Mich. 409 1983).

PA 304 created an alternative regulatory proceeding designed to address the perceived negative aspects of automatic billing adjustments. The new regulatory proceeding permits the monthly adjustment of rates to allow for full recovery of reasonable fuel, power, and transportation costs that utilities incur to serve customers. At least three months prior to an established 12-month period, utilities are required to file a Power Supply Cost Recovery (PSCR)[15] plan detailing their projected costs for the period with accompanying support. The utilities can bill amounts that will recover the costs as presented, unless the MPSC acts to stop them by issuing a temporary order setting other billing factors. Utilities can adjust their projections in midstream and roll in past imbalances to allow for a more timely recovery than waiting for a final MPSC order after a contested proceeding. The commission conducts their review as a contested case subject to intervention by appropriate parties, including those funded by the Utility Consumer Representation Board.[16]

Within three months following the completion of the established plan period, utilities are required to file a reconciliation application, where actual costs incurred and revenues collected pursuant to the plan are compared to see if the utility over- or under-collected their costs. In addition, those costs are subject to a reasonableness and prudence review (MCL 460.6(J) 2008).

Over the years, the results of these reconciliations (namely the over- or under-collection of reasonable costs by the utility) have been implemented in different ways. Initially, a surcharge or credit for a particular plan period was utilized to provide the utility recovery of their costs and not more or less and essentially close out that period. Currently, the MPSC employs the "roll in" method, whereby estimated over- or under-collections are included in a subsequent plan application and collected from or returned to customers as part of that period's billing factor.

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[15] Gas utilities file a Gas Cost Recovery (GCR) plan.
[16] Per PA 304, the Utility Consumer Representation Board was created, and is funded, through utility assessments.

As the utility cost paradigm has evolved, so has the nature of PA 304 proceedings. In recent years, to respond better to what and whom the utilities are paying for fuel, power, and transportation, PSCR applications now include transmission expenses, emission allowance expenses, and costs of pollution control chemicals. Again, the premise is to continue with the PA 304 framework of meshing more timely and full recovery of certain costs, with the review of the reasonableness and prudence of those costs, and the acknowledgement that these costs can vary based on external events and circumstances.

CERTIFICATE OF NECESSITY *(Michigan Common Law Act 3 of 1939, Section 460.6s Added Public Act 286, [2008])*

The Certificate of Necessity process—established by Public Act 286 in 2008—allows the commission to review planned utility investments and determine whether proposed plans merit preapproval. Prior to 2008, the commission could only evaluate utility investments upon completion, and whether or not a facility met the “used and useful” standard. Without commission approval, utilities are unable to recover the costs of an investment through rates.

The voluntary CON process allows an electric utility to apply for approval of plans to construct an electric generation facility, make a significant investment in an existing electric generation facility, or enter into a power purchase agreement for the purchase of electric capacity for a period of at least six years—as long as the costs for the proposed construction, investment, or purchase is at least $500 million and a portion of the costs would be allocable to retail customers in Michigan (MCL 460.6s 2008). A significant investment in an electric generation facility includes a group of investments reasonably planned to be made over a period of up to six years for a singular purpose, such as increasing the capacity of an existing generation plant. Environmental upgrades to existing electric generation facilities and renewable energy systems[17] are not eligible for CON. Utilities with fewer than one million customers can apply for a CON for projects that cost less than $500 million.

A utility’s application may request a CON based on one or more of the following criteria:

- The power to be supplied as a result of the proposed construction, investment, or purchase is necessary.
- The size, fuel type, and other design characteristics of the existing or proposed facility, or the terms of the power purchase agreement, represent the most reasonable and prudent means of meeting that power need.
- The price specified in the power purchase agreement will be recovered in rates from the electric utility's customers.
- The estimated purchase or capital costs of the existing or proposed electric generation facility, including the costs of siting and licensing a new facility and the estimated cost of power from it, will be recoverable in rates from the electric utility's customers, subject to a requirement that costs be reasonable.

Following an application’s filing, the commission has 270 days[18] to determine whether to grant or deny a CON. The commission’s determination must follow a contested case hearing, where all interested parties are given an opportunity to intervene. Interested parties must be allowed reasonable discovery before and during the hearing, in order to obtain evidence concerning the application—including the reasonableness and prudence of the construction, investment, or purchase for which the CON has been requested. The MPSC must grant approval for the CON if the plan satisfies all of the following requirements:

- The electric utility has demonstrated a need for the power that would be supplied by the existing or proposed facility or pursuant to the proposed power purchase agreement through its approved

[17] "Renewable energy system" means that term as defined in the Clean, Renewable, and Efficient Energy Act (MCL460.1011 2008).
[18] Within 150 days of filing an application, the utility may update its cost estimates if they have changed materially. This amendment does not alter the review period.

integrated resource plan (that complies with certain provisions as described in the next section of this outline).

- ❖ The information supplied indicates that the existing or proposed facility will comply with all applicable state and federal environmental standards, laws, and rules.
- ❖ The existing or proposed facility or purchase agreement represents the most reasonable and prudent means of meeting the power need relative to other resource options for meeting power demand, including energy-efficiency programs and electric transmission efficiencies.
- ❖ To the extent practicable, the construction or investment in a new or existing facility in Michigan is completed using a workforce composed of Michigan residents, as determined by the MPSC (except with regard to a facility located in a county bordering another state).

Following MPSC approval, a utility must provide periodic updates on a project's status, including actual costs and schedule. Once the utility's investment is considered used and useful, or as otherwise provided (for construction work in progress), the MPSC must include in a utility's retail rates all reasonable and prudent costs for a facility or agreement for which a CON has been granted. If the costs have not exceeded those approved, then the MPSC may not disallow recovery of costs a utility incurred pursuant to an agreement for which a CON has been granted. Any additional costs incurred by the utility will be included in retail rates only after the MPSC determines they were reasonable and prudent. A utility with costs exceeding the CON-approved amount is responsible to provide evidence that costs were incurred as the result of reasonable and prudent behavior. Any costs that exceed 110 percent of the CON-approved amount are presumed to have been incurred due to a lack of prudence. However, the MPSC may include any or all of these costs if it finds by a preponderance of the evidence that the costs were incurred prudently. A utility is free to proceed with their proposed plan absent commission approval, but would be unable to recover a project's costs through rates.

INTEGRATED RESOURCE PLAN (IRP) *(Michigan Common Law Act 3 of 1939, Section 460.6s Added Public Act 286, [2008])*

In Michigan, electric utilities are only required to prepare an Integrated Resource Plan (IRP) when they are seeking commission approval for a CON application. A utility's IRP filing must cover a ten-year planning horizon and include all of the following elements:

- ❖ A long-term forecast of the utility's load growth under various reasonable scenarios.
- ❖ The type of generation technology proposed for the facility and its proposed capacity, including projected fuel and regulatory costs under various reasonable scenarios.
- ❖ Projected energy and capacity purchased or produced by the utility pursuant to any RPS.
- ❖ Projected savings under any energy-efficiency program requirements and the projected costs for that program.
- ❖ Projected load management and demand response savings for the utility and the projected costs for those programs.
- ❖ Electric transmission options for the electric utility.

A company filing an IRP is required to analyze the availability of resources that could defer or displace the need for a proposed investment. These resources can include renewable energy, energy efficiency, load management, and demand response.

RENEWABLE PORTFOLIO STANDARD *(Public Act 295 of 2008, Part 2, Subpart A)*

In 2008, the Michigan Legislature passed Public Act 295—commonly called the Clean, Renewable and Efficient Energy Act. The objectives established for PA 295 include the following:

a) Diversify the resources used to reliably meet the energy needs of consumers in this state.
b) Provide greater energy security through the use of indigenous energy resources available within this state.
c) Encourage private investment in renewable energy and energy efficiency.

d) Provide improved air quality and other benefits to energy consumers and citizens of this state (MCL 460.1001 2008).

Michigan's renewable portfolio standard, established by PA 295, requires electric providers[19] to obtain 10 percent of their electric supply from renewable sources by 2015. Progress towards this goal is monitored and enforced by the MPSC. In 2009, each provider was required to file an initial renewable energy plan (REP), describing how they intended to meet the renewable standard requirements (MCL 460.1021 2008). The commission reviews these plans every two years. Electric providers whose rates are regulated by the MPSC are required to file annual renewable energy cost reconciliation cases.[20]

The incremental costs of compliance with the renewable energy standard can be recovered through a surcharge on customer bills.[21] To mitigate rate impacts, surcharges are limited to $3.00 per month for residential customers, $16.58 per month for secondary commercial customers, and $187.50 per month for primary commercial or industrial customers (MCL 460.1045 2008). The remaining costs represent the nonrenewable energy and capacity component of the total renewable generation; these are recovered through the PSCR process.

Michigan uses Renewable Energy Credits (RECs) to track compliance with the renewables standard. The Michigan Renewable Energy Certification System certifies all RECs and enables firms to trade or sell them. Seventy-one electric providers are obligated to meet an annual REC requirement (MPSC 2015). RECs are earned through operating renewable energy systems[22]. Each megawatt hour (MWh) of electricity generated from renewable sources is the equivalent of one REC. Another way for firms to meet the renewable standard is with Michigan Incentive Renewable Energy Credits (IRECs). In addition to the base REC, IRECS are issued for renewable projects that fulfill any of the following characteristics.

- One MWh produced from solar power equals two IRECS.
- One MWh of renewable energy produced on peak, excluding wind, equals one fifth of an IREC.
- One MWh of renewable energy produced off peak, but stored by advanced battery technology or pumped storage for use on peak, equals one fifth of an IREC.
- One MWh of renewable energy generated from a system constructed using a threshold of Michigan made equipment or labor equals one tenth of an IREC.[23]

A firm can also substitute Energy Optimization Credits (EOCs) and Advanced Cleaner Energy Credits (ACECs)[24] for up to 10 percent of their annual REC requirement. Each MWh of energy savings through energy optimization earns one EOC. A firm can earn ACECs for each MWh of electricity generated by a gasification facility, industrial cogeneration facility, or a coal-fired electric generating facility, if 85 percent or more of the carbon dioxide emissions are captured and permanently geologically sequestered. ACEC substitutions are one ACEC equals one REC for plasma arc gasification or industrial cogeneration. ACECs from other technologies are substituted at a ratio of ten ACECs equals one REC. To date, ACECs have only accounted for 5 percent of all credits produced (MIRECS September 2014).

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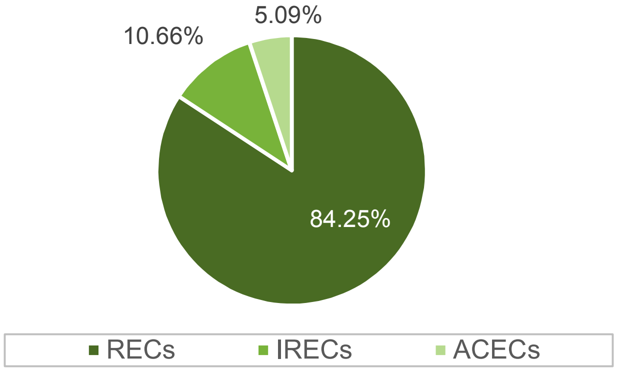
[19] All investor-owned electric utilities, cooperative electric utilities, municipal electric utilities, and alternative electric suppliers (AESs) within the state must comply with the RPS.
[20] Commission staff audits the pertinent revenues and expenses, determines the electric provider's compliance with its filed REP and assesses whether the provider has met its compliance targets.
[21] Commission approval is only required for rate-regulated electric providers.
[22] Defined by PA 295 Section 11, as a facility, electricity generation system, or set of electricity generation systems that use one or more renewable energy resources to generate electricity. Renewable resources include, but are not limited to, biomass, solar and solar thermal energy, wind energy, hydroelectric, wave energy, geothermal energy, municipal solid waste, and landfill gas.
[23] Credit only applies for first three years following the project's completion.
[24] Allows for consideration of clean energy systems not in commercial operation at the time of passage.

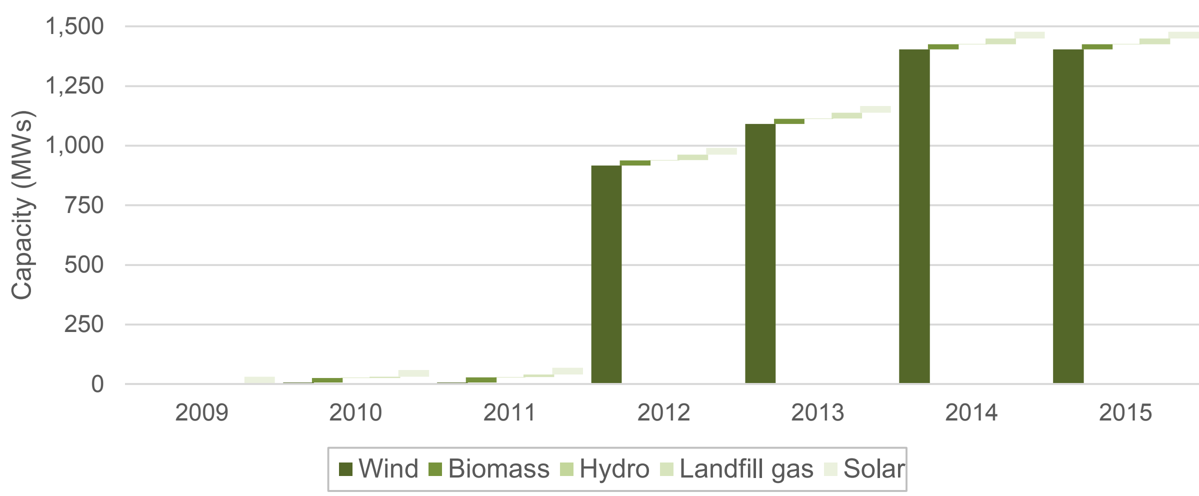
EXHIBIT 3.1. RECs Issued, 2009–2014 (MIRECS)



SOURCE: Michigan Renewable Energy Certification System (MIRECS).September 2014. *Annual Report for 2013-2014.* Available at: http://www.mirecs.org/wp-content/uploads/sites/4/2014/09/MIRECS-2013-Annual-Report-Public-Version.pdf (accessed 3/21/2015)

Since adoption, Michigan's RPS has resulted in the addition of more than 1,400 MWs of new renewable generation (MPSC 2015). Based upon a review of REPs filed with the commission, all providers are expected to be able to meet the 10 percent renewable energy standard in 2015.[25] For 2016 and each year thereafter, electric providers are required to maintain the same amount of RECs needed to meet the standard in 2015.

EXHIBIT 3.2. PA 295 Contract Renewable Energy Capacity



SOURCE: MPSC. February 13, 2015. *Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards*. Available at: http://www.michigan.gov/documents/mpsc/PA_295_Renewable_Energy_481423_7.pdf (accessed on 3/17/15)

[25]It was previously reported that Detroit Public Lighting (DPL) was not expected to meet the 10 percent renewable energy standard in 2015; however, all of DPL's customers became DTE electric customers effective July 1, 2014, and a five- to seven-year system conversion is in process that will transition former DPL customers to the DTE distribution system. In the interim, the MPSC has suspended all of DPL's renewable energy filings. DTE is expected to meet the 10 percent renewable energy standard in 2015.

ENERGY OPTIMIZATION PLAN *(Public Act 295 of 2008, Part 2, Subpart B)*

In addition to establishing the RPS, PA 295 established specific goals to reduce energy consumption. These goals were instituted in an effort to reduce future costs for customers, while delaying the need for new electric generation by reducing energy waste and promoting efficient energy consumption. Electric and natural gas utilities were required to submit an energy optimization plan with details about their program's design and estimated costs (MCL 460.1071 2008). Utilities were given the option to self-administer their EO program or collaborate with other utilities in a joint program.

EXHIBIT 3.3. Energy Optimization Program Participation by Electric Utility, 2013

	Independent Program	Efficiency United	MECA	MPPA	Totals
Electric investor-owned utility	2	6			8
Municipal utility	7	9	4	21	41
Electric cooperative	1	1	8		10
Program totals	10	16	12	21	59

SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs.* Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf (accessed 1/21/15)

The savings targets established by PA 295 increased progressively each year from 2009 to 2012 (MCL 460.1077 2008). The annual energy savings target in 2015 is 1 percent for electricity and .75 percent for gas. These annual savings targets remain in place until the imposed spending cap is reached. Under the current EO program, utility spending is limited to 2 percent of their annual revenue. Additional spending is allowed, but is subject to commission approval.

EXHIBIT 3.4. Annual Energy Savings Targets, Public Act 295 of 2008

	2008–2009	2010	2011	2012	2013	2014	2015
Electricity (MWhs)	0.30%	0.50%	0.75%	1.00%	1.00%	1.00%	1.00%
Natural gas (Mcf)	0.10%	0.25%	0.50%	0.75%	0.75%	0.75%	0.75%

NOTE: Annual savings goal determined as a percent of retail sales in the year two years prior.
SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs.* Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf (accessed 1/21/15)

A utility's EO plan must include the required level of funding for their proposed program (MCL 460.1071 2008). Rate-regulated utilities recover their program spending through commission approved surcharges on customer bills. To earn commission approval, a program must be cost-effective based on the Utility System Resource Cost Test (USRCT).

EXHIBIT 3.5. 2013 Average Residential EO Surcharge (dollars/month)

Investor-owned utility	$1.66
Electric cooperative	$1.16
Municipal utility	$0.84

SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs.* Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf (accessed 1/21/15)

The commission can approve incentives for rate-regulated utilities whose performance exceed the EO standard. The financial incentive cannot exceed 15 percent of the providers' actual annual energy-efficiency program spending or 25 percent of the customers net cost reductions as a result of the energy optimization plan, whichever is less (MCL 460.1075 2008). Through 2013, only Consumers Energy and DTE Energy have received performance incentives, but Indiana Michigan Power Company and SEMCO Energy Gas Company have received approval for the upcoming program year (MPSC November 2014).

EXHIBIT 3.6. Utility Performance Incentives Awarded or Anticipated through 2013

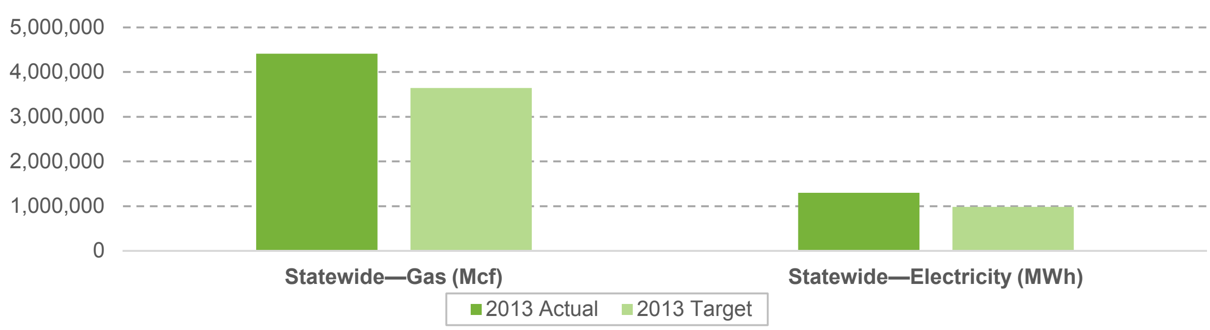
Program Year	Consumers Energy(Electric)	Consumers Energy (Gas)	DTE Energy (Electric)	DTE Energy (Gas)	Totals
2009	$3,323,612	$2,361,693	$3,008,829	$913,373	$9,607,507
2010	$5,076,731	$3,407,064	$6,200,000	$2,400,000	$17,083,795
2011	$7,281,670	$7,312,307	$8,400,000	$3,400,000	$26,393,977
2012	$10,027,210	$7,282,721	$10,500,000	$4,300,000	$32,109,931
2013*	$10,364,556	$7,166,544	$11,237,246	$3,848,020	$32,616,366
Totals	**$36,073,779**	**$27,530,329**	**$39,346,075**	**$14,861,393**	**$117,811,576**

SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs.* Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf (accessed 1/21/15)

Certain large electric customers are eligible to customize and implement their own EO plan. Eligible customers must have a peak demand of at least one MW, or an aggregate demand of at least five MW at all of their sites within a given service territory. Twenty-nine customers self-implemented EO programs in 2013.

MPSC publishes an annual report about the implementation of energy-efficiency programs within the state (MPSC November 26, 2014). For 2013, Michigan energy providers achieved 132 percent of their electric energy-efficiency targets and 121 percent of their gas energy-efficiency targets. Although savings targets are measured on an annual basis, customers will realize the benefits of the energy efficient upgrades over the life of the project. A recent MPSC report found that, "In 2013, aggregate EO program expenditures of $253 million by all natural gas and electric utilities in the state are estimated to result in lifecycle savings to customers of $948 million. For every dollar spent on EO programs in 2013, customers should expect to realize benefits of $3.75" (MPSC November 26, 2014).

EXHIBIT 3.7. Implementation of Energy Optimization Programs in Michigan



SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs.* Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf (accessed 1/21/15)

TRANSMISSION SITING *(Michigan Common Law Act 30 of 1995)*

The Electric Line Certification Act, Public Act 30 of 1995, gives the MPSC authority to regulate siting of transmission lines. An electric utility, affiliated transmission company, or independent transmission company proposing a major transmission project[26] is required to submit an application for a certificate of public convenience and necessity. Before the company files an application, they have to meet with elected officials and conduct a public meeting in each municipality impacted by the proposed line (MCL 460.566 2004). Once a company's application is filed with the MPSC, the commission will conduct a review of the application through a contested case proceeding. During the contested case the commission, or other intervening party may suggest a modification to the proposed route. The commission has one year after an application is filed to either grant or deny a certificate (MCL 460.568 2004). An application will be approved if the commission determines the following criteria have been met:

a) The public benefits[27] of the proposed major transmission line justify its construction.
b) The proposed or alternative route is feasible and reasonable.
c) The proposed project does not present an unreasonable threat to public health or safety.
d) The applicant has accepted the conditions contained in a conditional grant.

Pursuant to PA 295 Section 147, the MPSC established wind energy resource zones. These areas were identified as having the best potential for wind energy development in the state (MPSC January 2010). To facilitate the development of wind energy within these zones, PA 295 granted the MPSC the ability to expedite certain transmission projects. The commission has 180 days to approve or deny the application for an expedited transmission certificate (MCL 460.153 2008).

MERGERS, ACQUISITIONS, AND ASSET SALES *(Michigan Common Law Act 3 of 1939, Section 460.6q; Added 2008, Act 286) MPSC Order No. U-15795 March 18, 2009*

Public Act 286 expanded the MPSC's authority to include the acquisition, transfer of control, or merger of jurisdictional regulated utilities (MCL 460.6q 2008). Among other factors, the commission's evaluation of a proposed acquisition, merger, transfer, or encumbrance shall consider the following:

a) Whether the proposed action would have an adverse impact on the rates of the customers affected by the proposed transaction.
b) Whether the proposed action would have an adverse impact on the provision of safe, reliable, and adequate energy service in this state.
c) Whether the action will result in the subsidization of a nonregulated activity of the new entity through the rates paid by the customers of the jurisdictional regulated utility.
d) Whether the action will significantly impair the jurisdictional regulated utility's ability to raise necessary capital or to maintain a reasonable capital structure.
e) Whether the action is otherwise inconsistent with public policy and interest.

The commission must issue an order within 180 days from the date of application and has the ability to impose reasonable terms and conditions on the proposed transaction to protect either the utility or its customers. The utility may reject any terms and conditions imposed by the commission and not proceed with the transaction.

ELECTRIC CHOICE *(Michigan Common Law Act 3 of 1939, Section 460.10, Added 2000, Act 141; Amended 2008, Act 286)*

Public Act 141 of 2000 (MCL 460.10 2008) opened Michigan's electric market to alternative energy suppliers (AESs) allowing retail customers for the first time to choose who they buy electricity from. All AESs must be licensed by the MPSC before they can begin selling power in the state. The commission evaluates prospective suppliers to ensure they are financially capable, possess the technical competence

[26] A major transmission line is a line of five miles or more in length through which electricity is transferred at a voltage greater than or equal to 345 kilovolts.
[27] Quantifiable and nonquantifiable.

to engage in energy transactions, can meet safety requirements for electric operations, and comply with all other lawful obligations.

The introduction of retail open access required electric utilities to update the way they structure prices. Customers who purchase electricity from an AES still use power lines controlled by regulated utilities. Before retail open access electric providers, rates were bundled—meaning that the cost of generation, transmission and distribution were not separated out, instead prices were based on a utility's overall costs. Unbundled utility rates allow customers to pay only the portion of the system they use (460.10b(2) 2001).

Retail open access was amended in 2008 Public Act 286 (PA 286), which capped choice participation at 10 percent of a utility's weather-adjusted retail sales (MCL 460.10 2008). The MPSC monitors participation in electric choice programs and requires utilities to furnish information on the status of choice programs on their websites (MPSC 2009). The commission prepares an annual report detailing the status of electric choice programs in Michigan—as required by PA 286 (MCL 460.10u 2008).

CERTIFICATE OF CONVENIENCE AND NECESSITY *(Michigan Common Law Act 69 of 1929, Section 460.501-460.506)*

Electric and natural gas utilities wishing to construct or operate any public utility plant or system in a territory currently served by another utility must first obtain a Certificate of Convenience and Necessity from the MPSC. The utility's application must include the name of the municipality or municipalities that it intends to serve, the type of service to be rendered, and documentation of proper consent or franchise from such municipality or municipalities authorizing the transaction of local business. Once the petition is received, the MPSC will set a hearing to give the utility currently serving the territory in question an opportunity to present its case and will notify this utility at least ten days prior to the hearing. In an Act 69 filing, supporting information and detail must be filed to determine whether allowing multiple utilities to provide service within the same municipality is in the best interest of the public. Public interest is considered from the standpoints of public safety, duplication of facilities, and economic benefits. The applicant is to submit drawings, maps, and include information regarding the project's environmental impact. If the application is accepted, a certificate shall detail the territory in which the utility may operate. Any party wishing to contest a commission order or decree may file an appeal to the Court of Appeals within 30 days of issuance.

Section III.B. Utility Business Model

How Utilities Earn Revenue

One of the primary functions of state utility regulation is establishing retail rates. In Michigan, the public service commission regulates retail electric rates for eight investor-owned utilities and nine electric cooperatives (MCL 460.6 and MPSC n.d.). Municipal utilities, member-regulated electric cooperatives, and alternative energy suppliers (AES) are not rate regulated.

When a utility anticipates their existing rates will be insufficient to recover their revenue requirement, they file a general rate case with the MPSC to amend their rates (elements of rate case proceedings in Michigan are described in Section III. A). There are two main aspects of a general rate case. The first is determining a utility's revenue requirement. The revenue requirement is "the total amount of revenue the utility would need to provide a reasonable opportunity to earn a fair rate of return on its investment, given specified assumptions about sales and costs" (Lazar 2011 p.38.). State regulators review all utilities' investments to determine whether they have been incurred to provide service to customers and are reasonable and prudent. The revenue requirement formula is shown in Exhibit 3.8.

EXHIBIT 3.8. Utility Revenue Requirement

Revenue Requirement = Rate Base Investment X Rate of Return + Operating Expenses + Depreciation +Taxes

Rate Base Investment =
Net Plant in Service (= Total Plant in Service at Original Cost – Accumulated Depreciation) **+ Working Capital Allowances**

SOURCE: Formula provided by Michigan Public Service Commission based on formula found in Jim Lazar's *Electricity Regulation in the US: A Guide* (March 2011).

Once regulators have established a utility's revenue requirement, the next aspect of a rate case is setting appropriate rates. The general purpose of rate design is "to ensure the provision of safe, adequate, and reliable service at prices (or revenues) that are sufficient, but no more than sufficient, to compensate the regulated firm for the costs (including returns on investment) that it incurs to fulfill its obligation to serve" (Lazar 2011 p.6). There is variation in rates between customer classes, but the general formula for rates is a utility's revenue requirement divided by their expected sales volume, see the basic formula in Exhibit 3.9.

EXHIBIT 3.9. Basic Rate Formula

Customer Rates = Revenue Requirement / Volume of Customer Sales

SOURCE: Jim Lazar. March 2011. *Electricity Regulation in the US: A Guide.* p.41. Available at: http://www.raponline.org/document/download/id/645 (accessed 4/20/15)

Utility Behavior

Rate regulation creates economic incentives that impact how utilities behave and what business decisions they make. Public policy objectives related to electricity have changed dramatically in recent years. During most of the 20th century, the electric industry expanded rapidly, and policymakers at the time were focused on helping the industry meet growing demand and reach more customers. Today, policymakers are looking at ways to help customers reduce energy consumption and promote the development of cleaner energy sources. It is important that as public policy objectives change, utility regulation is updated to align incentives with established goals.

> *"The crux of this issue is that under long-standing, traditional utility regulation and rate structures, utilities' revenues are determined in large part by charges that vary depending on how much energy consumers use" (MPSC November 2013).*

The discussion that follows will explore how the incentives established by traditional rate regulation impact the decisions utilities make when evaluating different supply and demand side resources.

Supply Side Resources

Utility-owned Generation

Traditional regulation is well suited to compensating utilities for their investments in electric generation. As outlined above, a utility's revenue requirement is based on the size of their rate base. By increasing their rate base investment—such as by building a new power plant—their opportunity to earn a return increases. This structure has been a common source of criticism for traditional regulation, because it can be seen as an incentive for utilities to over-invest in infrastructure instead of considering other lower-cost resources. Over-investment is kept in check by state regulators who have the final say on utility costs and revenues. The cost of electric generation varies widely between different sources, see Exhibit 3.10 for a summary of the levelized cost for generation resources.

EXHIBIT 3.10. U.S. Average Estimated Levelized Cost of Electricity (LCOE) for Plants Entering Service in 2019 (2012 Dollars/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system LCOE	Subsidy[1]	Total LCOE including subsidy
Dispatchable technologies								
Conventional coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated coal-gasification combined cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural gas-fired								
Conventional combined cycle (CC)	87	14.3	1.7	49.1	1.2	66.3		
Advanced combined cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional combustion turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced combustion turbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Nondispatchable technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind-offshore	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydro[3]	53	72.0	4.1	6.4	2.0	84.5		

(1)The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2019, which include a permanent 10 percent investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30 percent investment tax credit on capital expenditures if placed in service before the end of 2016, and 10 percent thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation- adjusted production tax credit over the plant's first ten years of service or a 30 percent investment tax credit, if they are under construction before the end of 2013.
(2) Costs are expressed in terms of net AC power available to the grid for the installed capacity.
(3) As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
SOURCE: U.S. EIA. May 7, 2014. Levelized Cost and Levelized Avoided Cost of new Generation Resources in the Annual Energy Outlook 2014. Available at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm. (accessed 3/21/15)

Power Purchase Agreements

The creation of competitive wholesale markets allowed nonutility generators (NUGs) to own generation and sell electricity. As an alternative to owning all the resources needed to meet their energy needs, utilities can enter power purchase agreements (PPAs) with NUGs. A PPA is a contract between a buyer and seller to purchase electricity. While the benefits of PPAs vary depending on the specific terms of a contract, generally utilities benefit from these agreements because they can transfer some of the risks associated with constructing and operating power plants, diversify their portfolio, and mitigate volatility (S & P 2007).

In the context of traditional rate regulation, PPAs are treated differently than utility rate base investments. Unlike rate base investments, utilities do not typically earn a rate of return on PPAs (PWC 2008). Instead, power purchase costs are passed on to customers through a utility's power supply cost recovery (PSCR) mechanism.

Community Renewable Energy

There are several terms used regularly and interchangeably to reference community-based renewable energy resources, including community solar, solar gardens, shared solar, community-shared solar gardens, and more (GLREA 2014). While solar is the most prevalent source of community renewable energy, shared energy resources can come from different renewables. The essential part of these programs is that they allow customers to access shared renewable energy resources, located at a place other than their home. Michigan law already allows customers to generate electricity at their homes to meet their energy needs, through the state's net-metering programs, but this program doesn't work for all customers. Community renewables programs allow people who don't have the right location for renewable energy, renters, and others people left out by net-metering restrictions to access renewable energy. There are many different ways to design community renewables programs; three design options were recently discussed during the Solar Working Group (SWG) facilitated by MPSC staff (MPSC June 2014).

The first option considered by the SWG was a utility lease model. Utilities would own and operate a community resource and customers would lease their share of the projects output directly from the utility. This program design aligns with a utility's typical operations and existing rate structures because it doesn't alter a utility's customer base, allows them to recover their costs, and potentially earns a rate of return based on their investment.[28] The next option considered was a community renewables project with shared ownership between a third party and the customer. This option raises concerns for utilities because it reduces their sales volume, and they would still need to supply distribution services and back up energy. There are additional regulatory consideration to implementing models with third-party and customer-owned resources. The third option SWG members discussed was establishing a value of solar (VOS) tariff. According to the National Renewable Energy Laboratory, VOS programs should be designed around the following principles (NREL 2015):

1. Sufficient utility revenues for grid services provided to support solar growth
2. Recognize the VOS benefits and costs—not only to the utility system, but to society as well (to the extent the benefits are codified in utility financial structures)—and pay the project owner appropriately
3. Limit cost to customers, both those with solar and those without
4. Create a transparent VOS rate calculation methodology, including input assumptions and updates

Community solar programs have been small to date, but their success and the success of community renewable energy projects around the country have propelled discussion about ways to expand access in Michigan. Both Consumers and DTE have expressed interest in pursuing development of subsidy-free

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[28] The lease would need to be designed as an operating lease to allow the utility to earn a return on its investment (MPSC June 2014).

community renewable energy projects. In May 2015, the MPSC approved Consumers' request to develop a three-year, ten-MW community solar pilot as a part of their renewable energy plan (MPSC 2015).

Demand Side Options

Energy-efficiency Investments

One of the policy objectives established by PA 295 was to reduce energy consumption through the implementation of statewide energy-efficiency programs. Energy efficiency can be one of the most cost-effective options for meeting customers' energy needs (Lazar 2011 p.77). Despite this, utilities have a disincentive to implement energy-efficiency programs, because it reduces their sales volume. Falling sales put utilities at risk of not recovering their revenue requirement and authorized rate of return, at least until rates can be amended to account for decreased sales volume.

Several measures were included in PA 295 to make energy efficiency more attractive for utilities. Utilities are allowed to recover their full costs[29] associated with implementing energy-efficiency programs (MCL 460.1089 (1)). They were also allowed to capitalize any conservation equipment, materials, and installation costs with an expected economic life greater than one year (MCL 460.1089 (4)). Utilities were also authorized to apply for financial incentives tied to successful program implementation. These incentives were limited to either, 25 percent of the net cost of reductions a provider experienced as a result of the plan, or 15 percent of the providers' actual program expenditures for a given year (MCL 460.1075). To date, only Consumers Energy and DTE Energy have been awarded incentives, see Exhibit 3.11 for a summary of program incentives paid. In total, utilities spent $253 million in 2013 to implement these programs. These investments are expected to result in savings to customers of approximately $948 million, meaning that for every dollar spent customers receive $3.75 of benefit (MPSC November 26, 2014).

EXHIBIT 3.11. Utility Performance Incentives Awarded through 2013

Program Year	Consumers Energy(Electric)	Consumers Energy (Gas)	DTE Energy (Electric)	DTE Energy (Gas)	Totals
2009	$3,323,612	$2,361,693	$3,008,829	$913,373	$9,607,507
2010	$5,076,731	$3,407,064	$6,200,000	$2,400,000	$17,083,795
2011	$7,281,670	$7,312,307	$8,400,000	$3,400,000	$26,393,977
2012	$10,027,210	$7,282,721	$10,500,000	$4,300,000	$32,109,931
2013*	$10,364,556	$7,166,544	$11,237,246	$3,848,020	$32,616,366
Totals	**$36,073,779**	**$27,530,329**	**$39,346,075**	**$14,861,393**	**$117,811,576**

*Totals for 2013 are anticipated
SOURCE: MPSC. November 26, 2014. *2014 Report on the Implementation of the P.A. 295 Utility Energy Optimization Programs*. Available at: http://michigan.gov/documents/mpsc/2014_eo_report_475141_7.pdf. (accessed 1/21/15)

Customer-owned, Behind-the-meter Distributed Generation and Storage

PA 295 required the MPSC to establish a statewide net-metering program, allowing customers to own and operate electric generation sources in parallel with the grid (MCL 460.1173 (1)). Michigan's net-metering program allows customers to install enough generating capacity to meet their electricity needs. The energy produced by customer-owned resources can be used on site or transferred to the electric grid. Customers receive credits for the electricity they send to the grid, depending on what category their project fits in. Net-metering installations are broken into the following categories.

- **Category 1:** These customers are considered "true net-metering customers." Category 1 projects are limited to 20 kW inverter based systems. A true net-metering customer is credited the full retail rate

[29] Limited to spending cap and subject to commission approval.

for each kWh they supply to the grid. These credits are applied to the customer's bill, and any excess credits will be carried over to subsequent months.

- **Category 2:** The second category of net-metering customer is a modified net-metering customer. Projects in Category 2 are larger than 20 kW but smaller than 150 kW. Modified net-metering customers receive a credit for each kWh of excess electricity produced reimbursed at a rate determined by the commission. Category 2 projects are not subject to standby charges.
- **Categories 3, 4, and 5:** Net metering projects between 150 kW and 2 MW are also considered modified net-metering customers. These customers must pay standby charges equal to the retail distribution rate applied to their imputed energy usage. Excess generation is eligible for bill credits at a rate determined by the commission (R 460.601).

PA 295 limited the size of net metering programs to 1 percent of a utility's in-state peak load for a proceeding year, allocated between categories (MCL 460.1173). Enrollment in net-metering programs is still a long way from reaching the cap. The MPSC's *Net Metering & Solar Pilot Program Report for Calendar Year 2013* shows that participation is less 10 percent of the cap (MPSC August 2014).

These customer-owned, behind-the-meter generation resources represent a new variable that utilities have to consider in their planning process. As with energy-efficiency programs, net metering results in an overall sales reduction for utilities because customers can avoid purchasing from the grid when their behind-the-meter resources are supplying electricity. Utilities contend that net-metering presents another issue because it requires a utility to reimburse true net metering customers at the full retail rate, and results in additional costs being shifted to nonparticipating ratepayers.

Utility retail rates have two essential components: fixed costs and variable costs. When customers receive credit for the full retail rate, they avoid paying for both of these components. Utilities claim that net-metering customers still utilize the distribution grid and should be responsible for paying the fixed costs portion of rates (MPSC June 30, 2014).

Demand Response Resources

PA 295 also promoted efforts to expand load management efforts within the state. Load management (or demand response) is designed to reduce energy consumption during periods when energy demand is highest. By reducing the amount of energy use at these peak times, utilities can avoid the need to run higher cost generators or purchase capacity from the market and customers can avoid paying these higher costs. As a part of the *Readying Michigan to Make Good Energy Decisions* process, both Consumers Energy and DTE commented that, despite the potential savings from demand response programs, adoption has been limited due to barriers in existing regulation. Unlike energy savings achieved through energy-efficiency programs, demand response savings don't qualify for incentives (Quackenbush 2013). The estimated cost for demand response programs is shown in Exhibit 3.12.

EXHIBIT 3.12. Unit Cost of Energy Efficiency and Demand Response Measures

Year	Levelized Cost for Energy Efficiency Measures ($/kWh)	Levelized Cost for Demand Response Measures ($/kW-year)
2010	$0.02	$50.70
2020	$0.03	$61.81
2030	$0.03	$75.34

SOURCE: Electric Power Research Institute. January 2009. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S (2010–2030).* Available at: http://www.michigan.gov/documents/energy/EPRI_EnergyEfficiencyPotential1-2009_418129_7.pdf (accessed 5/9/15)

Section IV. Where Are We Going?

Environmental Regulations

One of the most significant drivers of change in the electric power sector has been recent action taken by the federal government to mitigate damage done to the environment. It is commonly recognized that the pollution of the air, water and land—as a result of human activity—is having adverse effects on the environment and human health. Through its research and regulatory programs, the EPA works to mitigate environmental degradation and restore health to human populations (U.S. EPA 2008). New rules and regulations are changing the way electric power producers operate.

The electric power sector provides nearly 40 percent of the energy consumed in the United States. More than 60 percent of that energy is produced from fossil fuels. Generating electricity from fossil fuels also produces emissions that impact the air, water, and land. The EPA is attempting to limit these impacts through a series of regulations designed to create a cleaner electric power sector; these regulations are having dramatic effects on the electric power industry.

EXHIBIT 4.1. Environmental Regulations

Clean Air Act (CAA)			Clean Water Act (CWA)	Resource Conservation and Recovery Act (RCRA)
Cross-state Air Pollution Rule (CSAPR)	Mercury and Air Toxics Standard (MATS)	Clean Power Plan	Cooling Water Intake Structures (CWIS)	Coal Combustion Residuals
110(a)(2)(D)(i)(I)	Sections 111 and 112	Sections 111(d) and 111(b)	316(b)	Subtitle D
Finalized 2011	Finalized 2011	Expected 2015	Finalized 2014	Finalized 2014

The Clean Air Act (CAA)

The CAA required the EPA to establish National Ambient Air Quality Standards (NAAQS) for harmful air pollutants. These standards are designed to improve and protect human health by limiting exposure to six common pollutants—carbon monoxide (CO), lead (PB), nitrogen oxides (NOx), ozone (O3), particulate pollution ($PM_{2.5}$ and PM_{10}), and sulfur dioxide (SO_2). States are required to develop and enforce air quality programs to reach NAAQS.

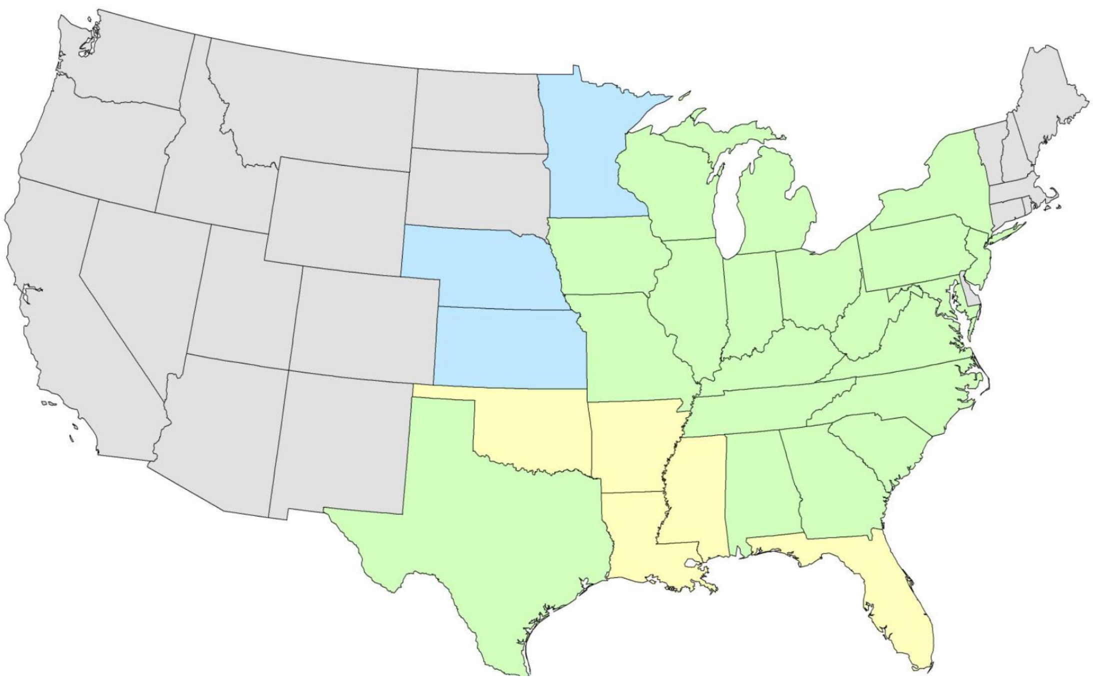
Cross-state Air Pollution Rule (CSAPR)—CAA 110(a)(2)(D)(i)(I)

The combustion of fossil fuels for electric generation produces 13 percent of all NOx and 70 percent of all SO_2 emissions nationally (U.S. EPA May 2014). Air pollution presents a unique enforcement challenge, because it does not respect state or regional boundaries. The "good neighbor" provision allows the EPA to regulate a state's air emissions when they substantially impact the ability of a downwind state to achieve NAAQS. The Cross-state Air Pollution Rule (CSAPR), finalized in 2011, requires 27 states in the eastern U.S. to reduce SO_2, NOx, and or $PM_{2.5}$ emissions from power plants (U.S. EPA 2011). A map of states impacted is shown in Exhibit 4.1. Power plants can achieve the emissions reductions required by CSAPR through any of the following strategies:

- Maintaining effective and frequent operation of already installed control equipment
- Using low sulfur coal
- Increasing generation from relatively cleaner units

- Installing existing, commercially proven technologies that are widely available and frequently used in this industry, such as low NOx burners, selective catalytic reduction (NOx reduction), scrubbers (flue gas desulfurization), or dry sorbent injection (U.S. EPA 2011)

EXHIBIT 4.2. States Included in CSAPR



States controlled for both fine particles (annual SO2 and NOx) and ozone (ozone season NOx) (20 States)
States controlled for fine particles only (annual SO2 and NOx) (3 States)
States controlled for ozone only (ozone season NOx) (5 States)
States not covered by the Cross-State Air Pollution Rule

SOURCE: U.S. EPA. N.d. *Large Map of Transport Rule States.* Available at: http://www.epa.gov/crossstaterule/statesmap.html. (accessed 3/21/15)

Mercury and Air Toxics Standard (MATS)—CAA Section(s) 111 and 112

On December 16, 2011, the EPA finalized the MATS, establishing the first national emission standards for hazardous air pollutants (NESHAP) from power plants. Electric generators fueled by coal and oil emit many harmful pollutants including mercury, acid gases, nonmercury metallic toxins, and organic air toxins. Under MATS, existing units are required to achieve a technology-based emissions standard set by the best performing sources (U.S. EPA April 2012). While many newer facilities already have control equipment in place to reduce such emissions, many older power plants do not. Power plants have several options to comply with the emissions reductions required by MATS, including (U.S. EPA April 2012):

- Using existing controls technologies to address toxic pollutants such as flue gas desulfurization (FGD), activated carbon injection (ACI), ACI with fabric filter (FF) or electrostatic precipitators (ESP)
- Fuel switching
- Retiring uneconomic units

Clean Power Plan—CAA Section(s) 111(b) and 111(d)

Fossil fuels consumed for electric generation are the largest source of carbon emissions in the nation (U.S. EPA January 2014). In June 2014, the EPA announced its plan to reduce carbon emissions from the nation's power plants. By 2030, the targets set by the Clean Power Plan will reduce carbon dioxide

(CO_2) emissions from power plants by 30 percent— relative to their levels in 2005. The proposed plan sets emissions reduction goals for individual states and allows states to develop their own strategies to meet the goals. The EPA proposed four primary building blocks for complying with the plan:

5. Make fossil fuel plants more efficient through a 6 percent reduction in heat rates
6. Increase the capacity factor of natural gas combined cycle plants
7. Utilize zero carbon generation such as renewables and nuclear plants more frequently
8. Increase energy efficiency and demand-side management (U.S. EPA June 2014)

The EPA received over four million submissions during the plan's public comment period. The final rule is expected to be issued in September 2015 (U.S. EPA January 2014).

The Clean Water Act (CWA)

The recognition that the nation's waterbodies were being adversely affected by human activity prompted Congress to pass the Clean Water Act. The law established the EPA's authority to implement regulations and standards aimed at restoring the quality of the nation's water resources. Of main concern in the CWA was the elimination of point source pollution and the discharge of toxic chemicals, but the law also expressed the desire to protect aquatic organisms and ecosystems (CWA 33 U.S.C § 1251(a)(2)).

Cooling Water Intake Structures (CWIS)—CWA Section 316(b)

Chemical pollution is only one factor posing a threat to aquatic life. Many industrial facilities and electric power generators that produce large amounts of heat, rely on water resources to cool their plants. These facilities withdraw millions of gallons per day through cooling water intake structures. Aquatic organisms face physical threats from these withdrawals as they are pulled into the cooling system or impinged on filters.

Pursuant to CWA Section 316(b), the EPA requires that facilities with cooling water intake structures are evaluated and permitted through the National Pollutant Discharge Elimination System (NPDES). The location, design, construction, and capacity of these structures must reflect the best technology available to minimize environmental impacts (U.S. EPA May 2014). The final rule governing cooling water intake structures at new and existing facilities was released on May 19, 2014, and it will impact more than 1,000 facilities. Facilities covered under the rule must comply with national best technology available standards for entrainment and impingement. The rule has three primary components:

1. Facilities withdrawing more than two million gallons per day must reduce fish impingement by through approved technologies.
2. Facilities withdrawing at least 125 million gallons per day must conduct a study evaluating ways to reduce impacts on fish populations and design a site-specific approach to reduce impingement.
3. New electric generating units can pursue one of two national entrainment standards to reduce entrainment and impingement (U.S. EPA May 2014).

Coal Combustion Residuals (CCR)—Resource Conservation and Recovery Act (RCRA) Subtitle D

More than 850 million tons of coal was consumed for the generation of electricity in 2014 (U.S. EIA January 20, 2015). Burning coal results in coal combustion residuals (CCR), commonly referred to as coal ash. Each year, the United States produces more than 100 million tons of coal ash, making it one of the largest sources of industrial waste (ACCA n.d.). The EPA encourages the beneficial reuse of coal ash; it is commonly repurposed into concrete, building materials, or other products. Unfortunately, the majority of coal ash is disposed of in landfills or surface impoundments at electric generating facilities. If stored improperly, coal ash contaminants could leach into groundwater or blow into the air. Following an unprecedented coal ash spill in 2008, the EPA began creating new safety standards to regulate the storage of coal ash (U.S. EPA March 2015).

On December 19, 2014, the EPA issued the final rule establishing minimum requirements for coal ash storage in landfills and surface impoundments. The rule—established under the Resource Conservation and Recovery Act, Subtitle D—requires storage facilities to meet minimum structural design criteria, place restrictions on where new facilities can be sited, and have site owners install monitoring wells (U.S. EPA December 2014).

Aging Infrastructure

The demand for electricity grew dramatically during the second half of the 21st century. Annual electric generation doubled between 1949 and 1956, again between 1956 and 1967, and for a third time between 1967 and 1985 (U.S. EIA February 24, 2015). This growth sparked huge investments in electric infrastructure to keep up with demand. Many of these investments are still a part of the nation's generation portfolio. Across the country, 73 percent of coal plants and 51 percent of all electric generation is at least 35 years old (U.S. EIA June 16, 2011). The electric grid built to supply electricity to more homes and businesses is connected via transmission and distribution lines. The electric grid connects more than 146 million customers across 6 million miles of transmission and distribution lines (MIT 2011). This electric infrastructure is aging. As it ages and is subsequently replaced, there is significant potential to update the electric grid and expand the use of emerging technologies.

Combined coal, natural gas, and nuclear accounted for more than 90 percent of all electricity produced in Michigan (U.S. EIA February 17, 2015). Michigan's coal power plants were predominantly built between 1950 and 1980. The last major[30] coal power plant—DTE's Belle River—was finished in 1985. Michigan's coal fleet—on average—has been in service more than 50 years (U.S. EIA February 17, 2015). Michigan's four nuclear reactors were built between 1972 and 1988. DTE's Fermi nuclear plant was the most recent addition. No new baseload coal or nuclear facilities have been built in the state in over 25 years. Since 1990, the majority of new generating capacity—nearly 8,000 MWs—built within the state has been fueled by natural gas. Since the establishment of Michigan's RPS in 2008, the state has added 1,500 MWs of new renewable capacity (MPSC February 2015). Information about Michigan's generating fleet is shown in the Exhibits 4.2 and 4.3.

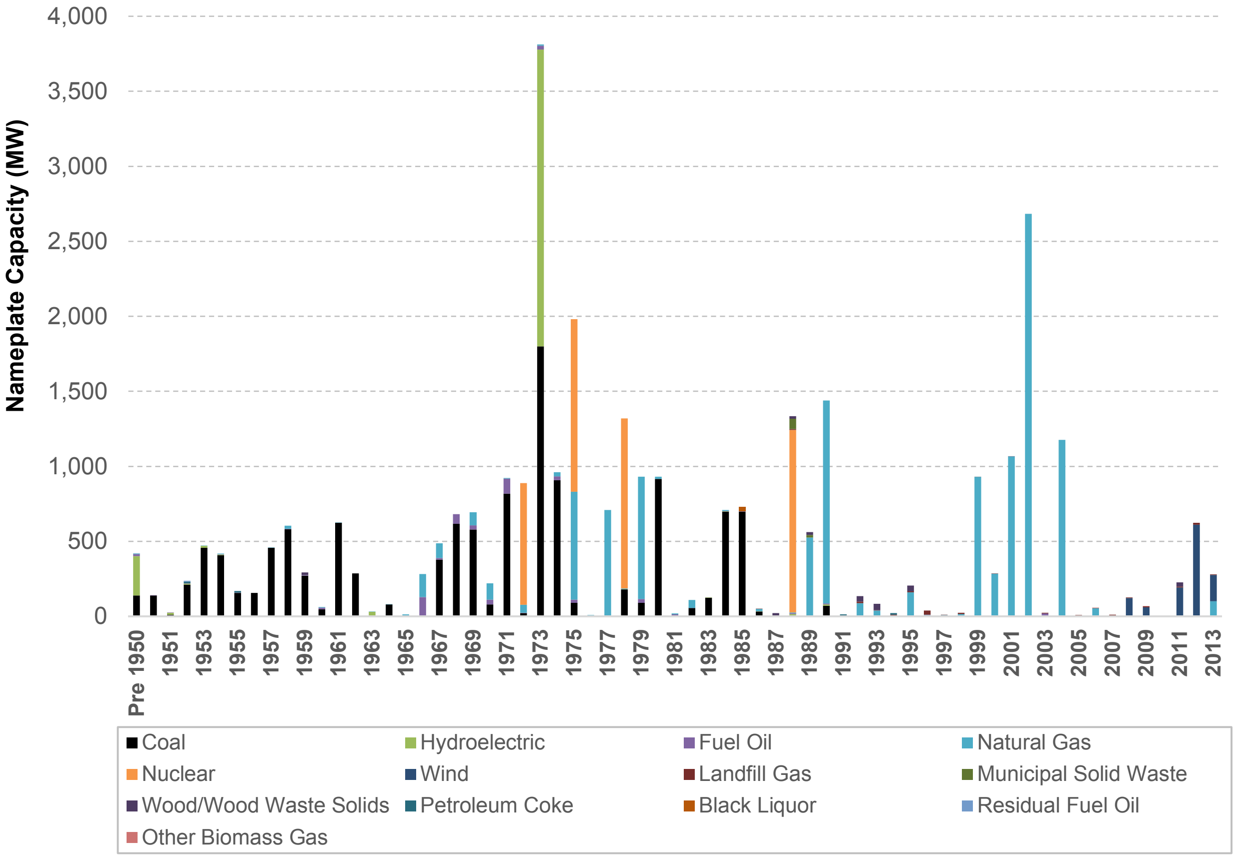
EXHIBIT 4.3. Inventory of Electric Generating Units, 2013

Fuel Source	Summer Capacity (MWs)	% of Capacity	Number of Units	Number of Facilities	Average Number of Years in Operation
Coal	10895.4	37.1%	66	28	50.76
Hydroelectric	2203.4	7.5	238	57	71.48
Petroleum	577.0	2.0	143	47	40.61
Natural gas	10308.8	35.1	174	21	26.66
Nuclear	3929.1	13.4	4	3	36.75
Wind	1080.3	3.7	17	16	4.29
Landfill gas	115.7	0.4	89	21	15.65
Municipal solid waste	79.3	0.3	2	2	26.50
Wood/wood waste solids	211.0	0.7	9	10	26.00

NOTE: Age calculations based on average of initial operating year.
(Average Age = (Sum of Operating Year for All Units, by fuel source) / Number of Units, by fuel source)
SOURCE: U.S. EIA. February 17, 2015. *Form EIA-860*. Available at: http://www.eia.gov/totalenergy/data/monthly/. (accessed 3/21/15)

[30] Three smaller coal-fueled power plants were built between 1986 and 1990. These plants have a cumulative summer capacity of 111 MWs (U.S. EIA Form 860).

EXHIBIT 4.4. Michigan Electric Generating Capacity Additions, by Year 1901–2013 (MWs)



SOURCE: U.S. EIA. February 17, 2015. *Form EIA-860*. Available at: http://www.eia.gov/totalenergy/data/monthly/. (accessed 3/21/15)

The decision to maintain generating assets comes down to economics. When a plant's expected costs exceed the expected lifetime revenue, then the plant will likely be retired. Environmental regulations are playing a major role in determining the future for some of Michigan's aging generating assets—especially coal plants. A recent survey of electric providers in MISO found eight to ten GWs of capacity is at risk of retirement because the costs of environmental compliance associated with MATS and CSAPR (Potomac 2014). As older facilities are retired either due to age or increased costs, there is the opportunity to transition to new, cleaner, more efficient sources of electricity.

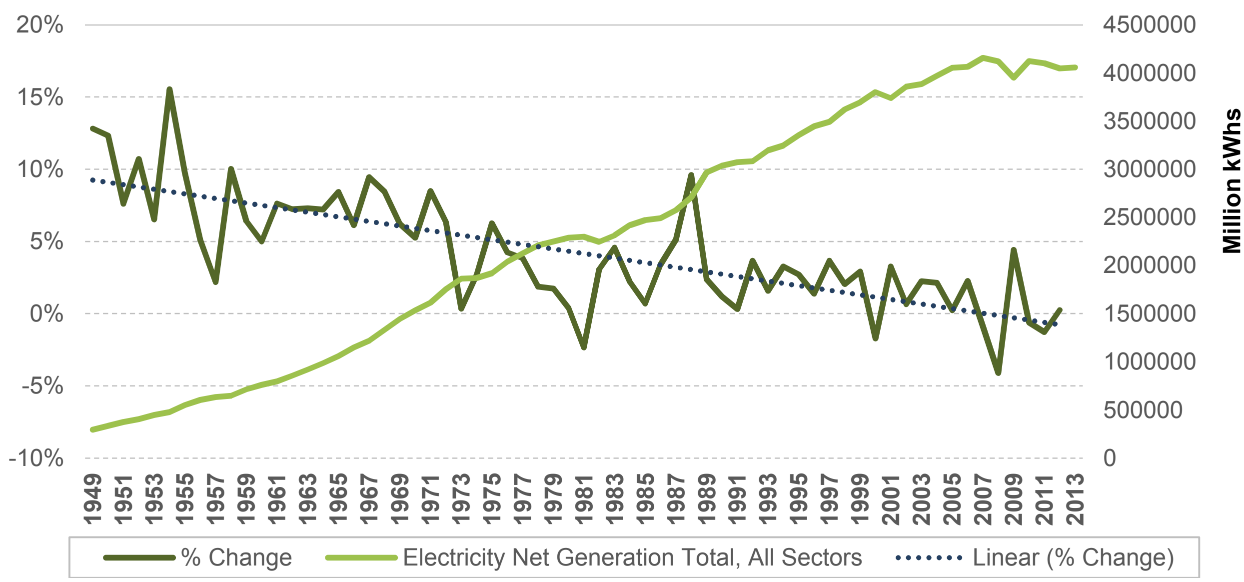
Reduced or Flat Load Growth

Demand for electricity increased significantly over the past 65 years, but the growth rate has gradually slowed over each decade during the same time period as shown in Exhibit 4.5. The growth rate peaked during the 1950s at 9.26 percent per year, but by 2010 it had fallen below 1 percent, see Exhibit 4.5 (U.S. EIA February 24, 2015). Part of the reason growth has slowed is energy consumption has become more efficient.[31] New efficiency standards for appliances, better building codes, and technological innovations

[31] Efficiency can refer to any number of improvements that help reduce the amount of energy needed to continue providing the same service (Lawrence Berkley National Laboratory n.d.).

have helped lower electricity usage in homes and businesses. In addition to using energy more efficiently, demand has fallen in recent years due to steep economic downturn. Electricity use fell 5 percent during the "Great Recession"[32], and generation of electricity has yet to recover to prerecession levels (U.S. EIA February 24, 2015).

EXHIBIT 4.5. U.S. Net Electric Generation Total, All Sectors and Percent Change in Electric Generation, 1950–2013



SOURCE: U.S. EIA. March 25, 2015. *Form EIA-923*. Available at: http://www.eia.gov/electricity/data/eia923/. (accessed 4/4/15)

EXHIBIT 4.6. Characteristics of Net Electric Generation for All Sectors, 1949–2013

	1950s	1960s	1970s	1980s	1990s	2000s	2010–2013
Average growth rate per decade	9.26%	7.32%	4.55%	2.85%	2.22%	0.70%	0.70%
Years with negative growth	0	0	0	1	0	3	2

SOURCE: U.S. EIA. February 24, 2015. *February 2015 Monthly Energy Review Table 7.2a*. Available at: http://www.eia.gov/totalenergy/data/monthly/ (accessed 3/21/15)

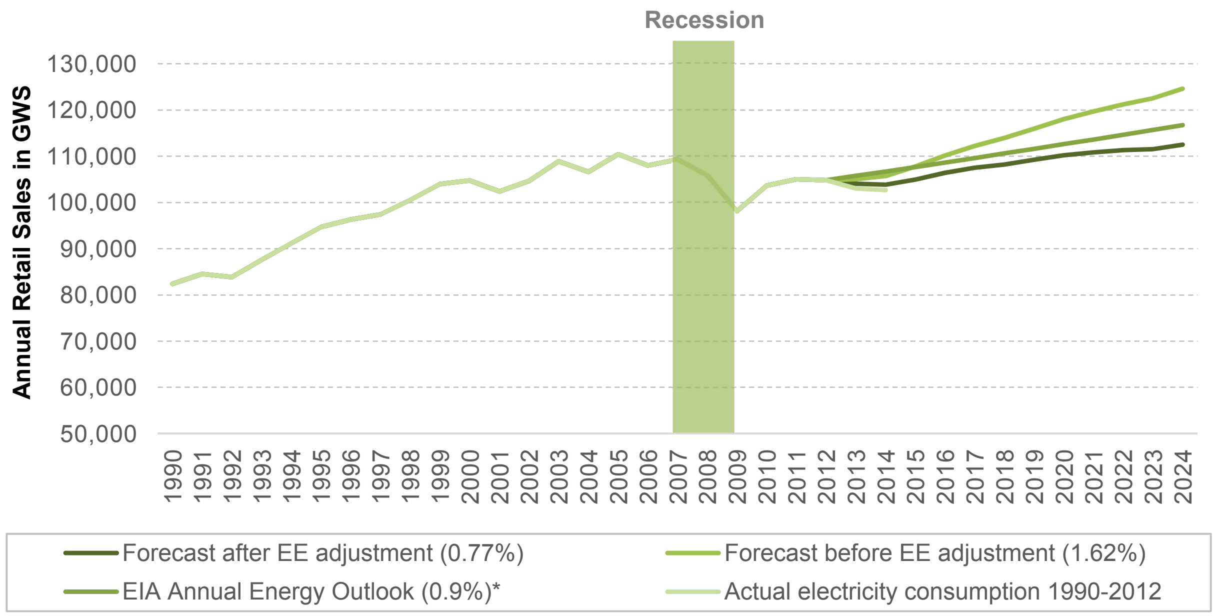
Projected Load

It is impossible to know what new technologies will affect the energy industry or how demand will change in the future. Building a power plant can take years and, in some cases, cost billions of dollars. For energy providers to make wise investments, they must be able to accurately predict the growth in demand for electricity. Forecasting energy demand is a complex task that relies on a series of computer models and statistical tools.

[32] The "Great Recession"—lasting from December 2007 through June 2009—was the longest and most severe economic downturn since the Great Depression (Isidore 2010).

Recent electric load forecasts anticipate electric demand will grow slowly over coming years. The State Utility Forecasting Group recently published an electric load forecast for the MISO RTO. The forecast is broken down by state, covering a ten-year period from 2013 to 2024. It projects that demand for electricity will grow at a modest pace of 1.62 percent over the next decade. When accounting for Michigan's goal to reduce energy consumption by 1 percent per year, the projected growth slows to 0.77 percent (Gotham 2014). Various electric load forecasts are shown in Exhibit 4.7.

EXHIBIT 4.7. Forecasted Electric Load in Michigan



SOURCE: U.S. EIA. May 7, 2014. *Annual Energy Outlook 2014.* Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf. (accessed 3/3/15); Douglas J Gotham et al. November 2014. *MISO Independent Load Forecast*. Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20141217/20141217%20PAC%20Supplemental%202014%20Independent%20Load%20Forecast.pdf. (accessed on 12/1/14)

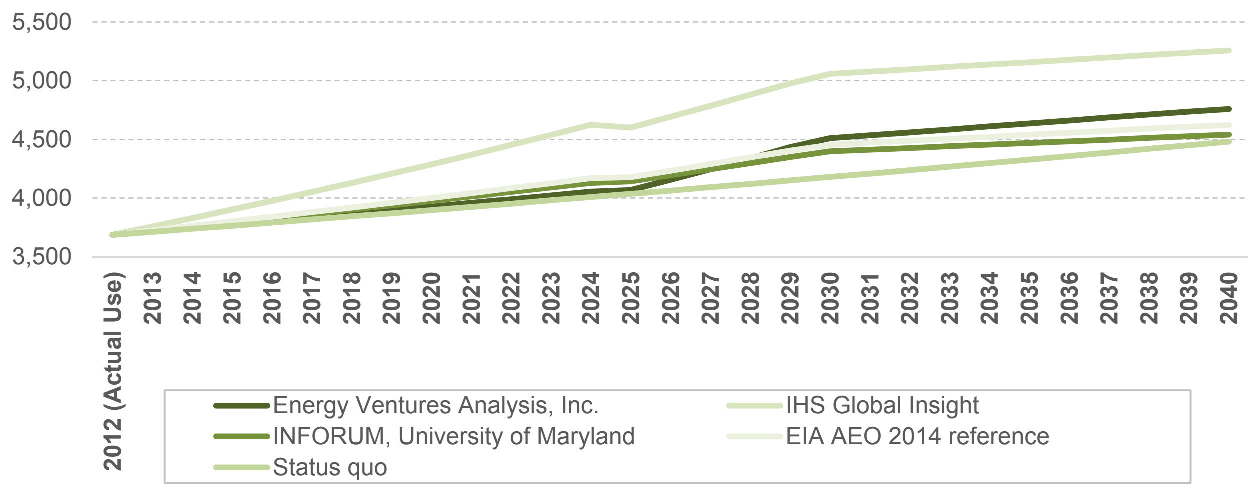
National forecasts project similar low growth in electric demand in coming years. The EIA's *Annual Energy Outlook* includes several electric demand projections for the period of 2012 to 2040. EIA's reference case forecast estimates that energy demand will increase by less than 1 percent per year. The most robust growth forecast—made by IHS Global Insight—estimates that energy demand will grow by 2 percent per year until 2018, then slowing to 1.5 percent through 2040 (U.S. EIA April 2014). Exhibits 4.8 and 4.9 show the different national load forecasts presented in the *2014 Annual Energy Outlook.*

EXHIBIT 4.8. Various Load Forecasts from EIA Annual Energy Outlook 2014, All Customer Classes (billion kWhs)

	EIA AEO 2014 Reference	Energy Ventures Analysis, Inc.	IHS Global Insight	INFORUM, University of Maryland
% change 2012–2040	25.42%	29.06%	42.59%	23.14%
Projected growth	937	1,071	1,570	853

SOURCE: U.S. EIA. May 7, 2014. Annual Energy Outlook 2014. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf. (accessed 3/3/15)

EXHIBIT 4.9. Projections for Electric Sales,
All Customer Classes, 2012–2040 (billion kWhs)



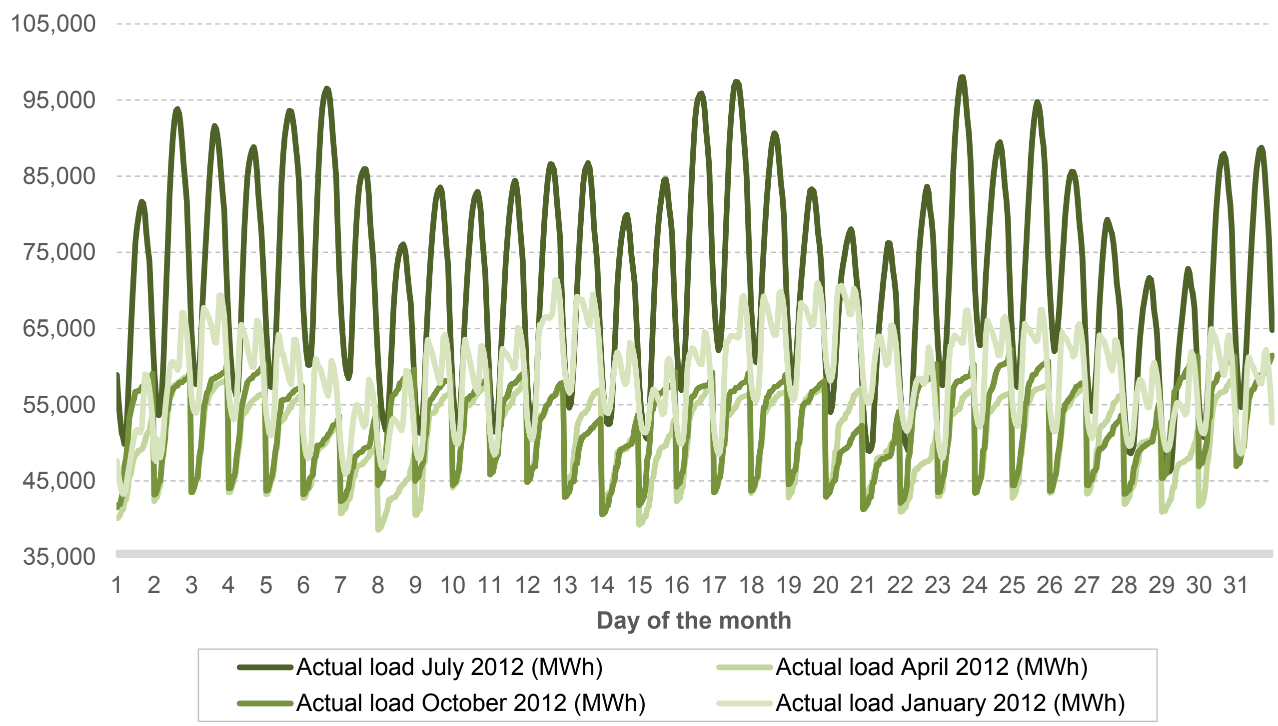
SOURCE: U.S. EIA. May 7, 2014. Annual Energy Outlook 2014. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf. (accessed 3/3/15)

Changing Fuel and Generation Economics

Electricity use varies from hour to hour each day, and from month to month during the year. Demand is typically greater during the middle of the day than at night, and is highest during summer months when temperatures rise. Because of these variations in electric load, electric power producers rely on a diverse portfolio of generating assets to meet demand. Electric generators are dispatched to meet increased demand based on their variable operating costs. Generally, plants with the lowest variable costs will be dispatched first, with more costly plants only being called upon if demand continues to rise (U.S. EIA 2012).

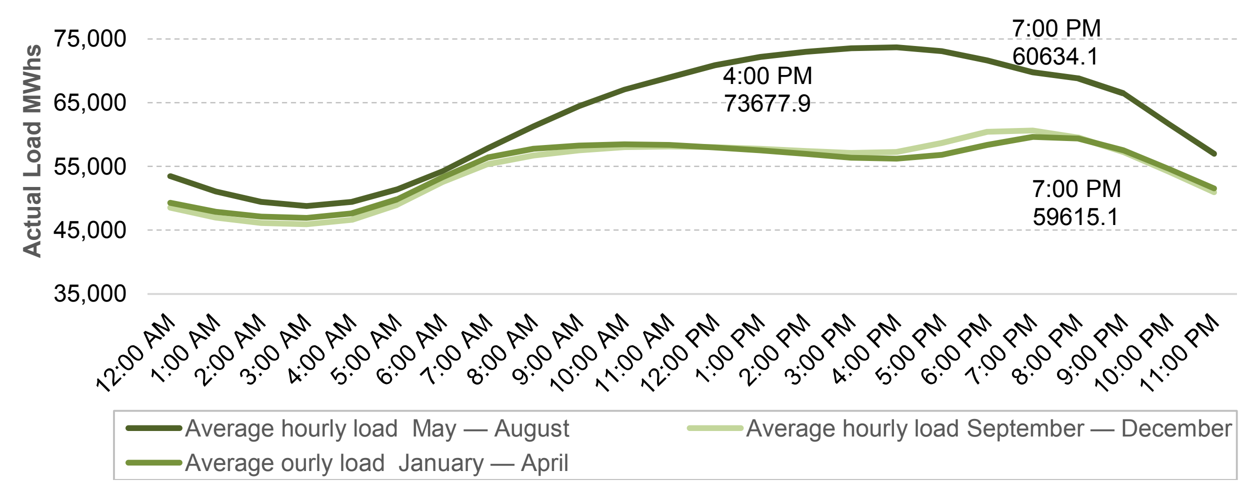
Some plants—predominately coal and nuclear—are used to supply baseload electricity because of their low variable operating costs. When demand rises, other generating capacity is brought online. These peaking plants generally have higher variable costs, but are able to respond quickly to increased demand. Generation dispatch in Michigan is managed by RTOs—MISO or PJM. Exhibit 4.10 captures the variation in electric load over a one-month period and throughout different months in the year. Exhibit 4.11 illustrates that same variation seen hour by hour throughout an average day.

EXHIBIT 4.10. MISO Daily Variation in Electric Load, 2012 (MWhs)



SOURCE: Midcontinent Independent System Operator, Inc. January 2, 2015. Archived Historical Regional Forecast and Actual Load, 2012. Available at: https://www.misoenergy.org/Library/MarketReports/Pages/ArchivedHistoricalRegionalForecastandActualLoad.aspx (accessed 4/15/15)

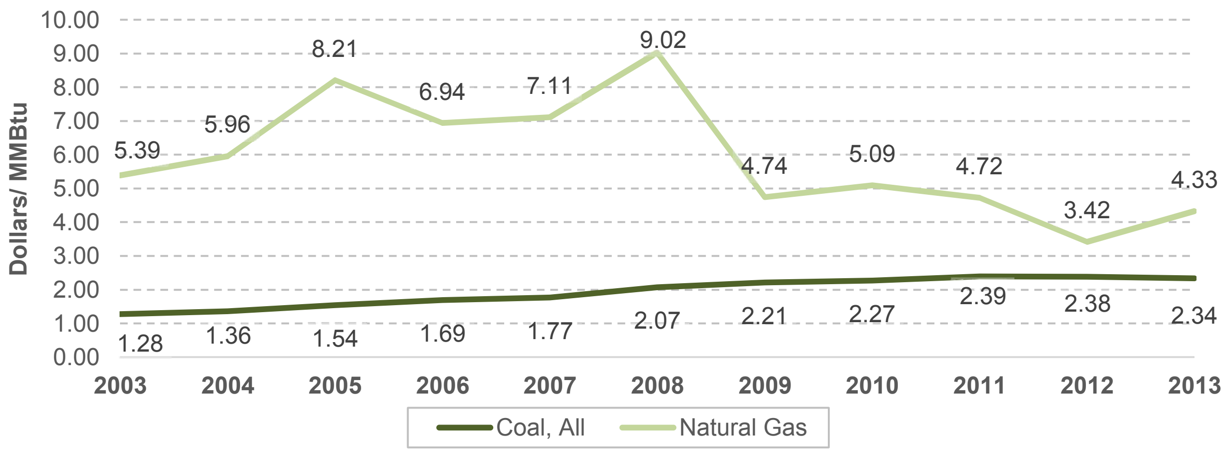
EXHIBIT 4.11. MISO Average Daily Electric Load, 2012 (MWhs)



SOURCE: Midcontinent Independent System Operator, Inc. January 2, 2015. *Archived Historical Regional Forecast and Actual Load, 2012.* Available at: https://www.misoenergy.org/Library/MarketReports/Pages/ArchivedHistoricalRegionalForecastandActualLoad.aspx (accessed 4/15/15)

In recent years, changing economic conditions have started to impact what resources are being dispatched to meet variable energy need. Fuel prices make up a significant portion of variable costs for power plants running on fossil fuels (Potomac Economics 2012). Coal has historically been the dominant fuel for electric supply in Michigan and for many parts of the country, but the average price of coal delivered to the electric power sector has increased approximately 4 percent annually from 2007 to 2011. During the same period, natural gas prices fell dramatically and have remained relatively stable, as shown in Exhibit 4.51. This was a result of abundant domestic resources and improved production technologies (U.S. EIA April 2014). Increased costs for coal-fired power plants and more competitive natural gas prices have led to greater utilization of natural gas-fired generation (U.S. EIA April 2014 p. 74.).

EXHIBIT 4.12. Weighted Average Price for Fossil Fuels in Electric Power Industry, 2003–2013



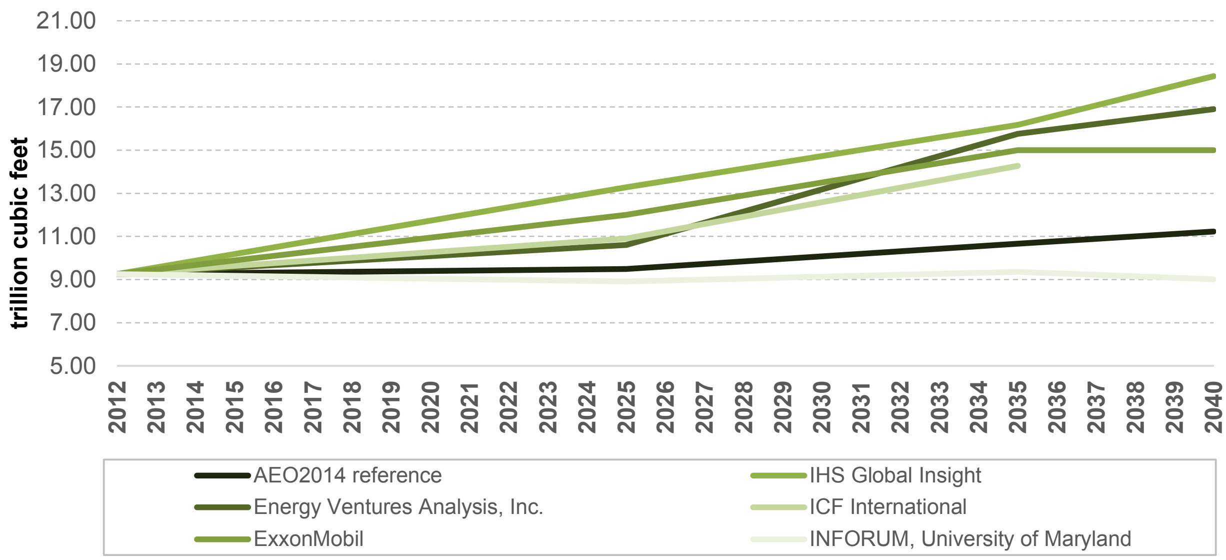
SOURCE: U.S. EIA. March 25, 2015. *Form EIA-923*. Available at: http://www.eia.gov/electricity/annual/html/epa_08_01.html. (accessed 3/20/15)

Projections for Natural Gas

According to projections by IHS Research, natural gas generation will grow by 7 percent annually through 2020 (IHS February 2015). As illustrated in Exhibit 4.13, the EIA projects that by 2034, natural gas will replace coal as the dominant fuel source for electricity, and the electric power industry's consumption of natural gas will increase by 0.7 percent annually growing by about two trillion cubic feet from 2012 to 2040 (U.S. EIA April 2014).

Production of natural gas is expected to outpace growing consumption in the United States through 2040. Expanded production is largely attributed to enhanced recovery technologies and the expansion of shale gas (U.S. EIA April 2014). Despite the expectation that production will grow more rapidly than consumption, natural gas prices are expected to rise in coming years. The U.S. EIA published a series of industry projections for natural gas prices in its *2014 Annual Energy Outlook*, these projections are shown in Exhibits 4.13 and 4.14.

EXHIBIT 4.13. Projected Natural Gas Consumption for Electric Generation (trillion cubic feet)



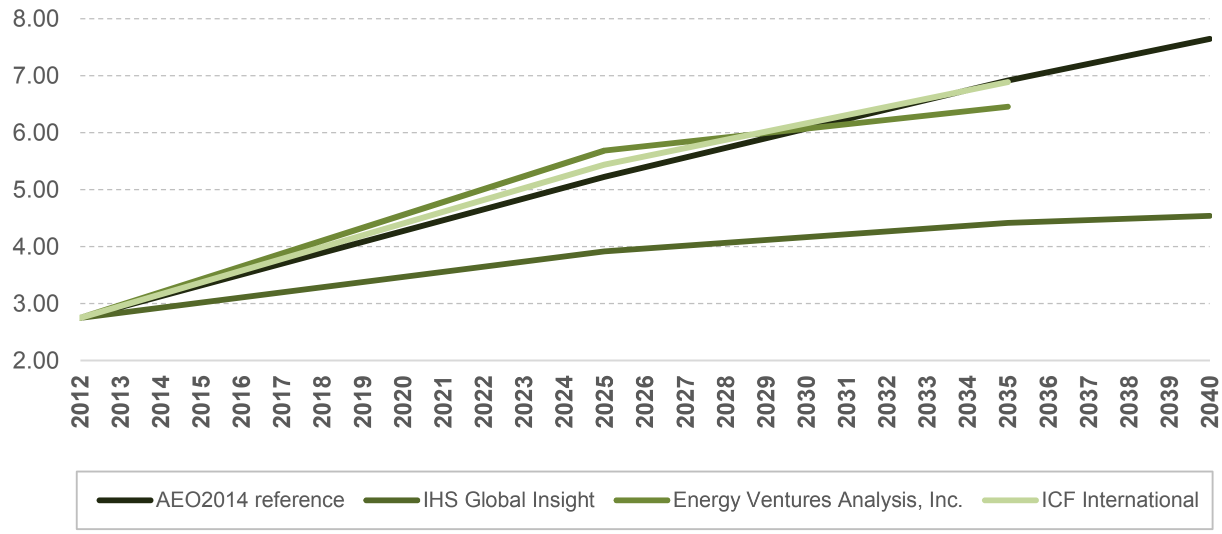
NOTE: Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.
SOURCE: U.S. EIA. May 7, 2014. Annual Energy Outlook 2014. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf. (accessed 3/3/15)

EXHIBIT 4.14. Projections for Natural Gas Prices, Henry Hub Spot Market Price (2012 Dollars/ million Btu)

	2012 (actual)	2025	2035	2040
AEO2014 Reference	2.75	5.23	6.92	7.65
IHS Global Insight	2.75	3.92	4.42	4.54
Energy Ventures Analysis, Inc.	2.75	5.69	6.46	
ICF International	2.75	5.44	6.89	

SOURCE: U.S. EIA. May 7, 2014. Annual Energy Outlook 2014. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf. (accessed 3/3/15)

EXHIBIT 4.15. Henry Hub Spot Market Price, 2012 (Dollars/Million Btu)



SOURCE: U.S. EIA. May 7, 2014. Annual Energy Outlook 2014. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf. (accessed 3/3/15)

Although natural gas prices are expected to rise over the next several years, it is still expected to be the dominant fuel for new generating capacity. The EIA's forecast projects that natural gas will make up 73 percent of all new capacity from 2012 to 2040 (U.S. EIA April 2014). The second largest source of new capacity during this period is expected to come from renewable energy technologies. The EIA projects that 24 percent of new capacity will be from renewable generation (U.S. EIA April 2014). These projections are available in Appendix L. In many cases, the development of renewable generation has been brought on by state policies like renewable portfolio standards or federal tax credits. The costs of many renewables have declined in recent years and have been developed in Michigan for less than the cost of a new coal plant[33], as shown in Exhibit 4.16.

EXHIBIT 4.16. Weighted Average Levelized Renewable Energy Contract Prices (Dollars/ MWh)

Technology	Wind	Digester	Biomass	Landfill	Hydro
Consumers Energy weighted average	$90.60	$137.77	NA	$106.21	$121.31
DTE Energy weighted average	$64.59	N/A	$98.94	$98.97	N/A
Combined weighted average	$74.52	$137.02	$98.94	$104.05	$121.31

SOURCE: MPSC. February 13, 2015. *Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards.* Available at: http://www.michigan.gov/documents/mpsc/PA_295_Renewable_Energy_481423_7.pdf (accessed 4/15/15)

[33] Compared to $133/ MWh for a new coal plant (MPSC February 13, 2015 p. 30).

Technology Innovation

The existing utility system model is shifting—from one based on centralized electric generation resources to a highly granular system more reliant on distributed, diverse energy resources. These resources include demand-side management capabilities and energy-efficiency measures. This new energy system requires management and coordination of energy system inputs and outputs and the deployment of intelligent communication and advanced control technologies necessary to interconnect, integrate, and harmonize the power system.

Distributed Energy Resources

Businesses and consumers are beginning to see a variety of new energy products and services coming to market collectively referred to as distributed energy resources (DERs). DERs are defined by the Electric Power Research Institute as "smaller power sources that can be aggregated to provide power necessary to meet regular demand" (EPRI 2014). DERs includes power generation and energy management technologies and services that have the potential to provide reliable alternative power, reduce loads, reduce peak demand, improve power quality, and enhance grid resiliency. DERs can be categorized as follows:

- **Fossil fuel-based distributed generation (DG) technologies:** These include combined heat and power (CHP) technologies that use natural gas, biomass, or petroleum; microturbines; fuel cells; reciprocating engines; and sterling engines.
- **Renewable energy DG technologies:** These include solar PV, small wind turbines, geothermal, and small hydroelectric facilities.
- **Demand-side management technologies and energy services:** These technologies and services aggregate energy-efficiency measures, behavioral energy efficiency, dynamic pricing, load scheduling, automated energy management, and demand response into energy system resources.
- **Energy services and grid support:** Technologies that store energy—batteries, flywheels, compressed air, and thermal storage—can also provide grid services like frequency regulation and voltage support. Grid-connected electric vehicles (V2G) can provide similar services.
- **Interconnection and grid integration technologies:** These include advanced controls and sensors, communication devices, inverters, synchrophasors, smart thermostats, and advanced metering infrastructure that control and manage energy.

Unlike conventional power plants that generate electricity and use the transmission and distribution system to deliver power monodirectionally to end users, DERs are heterogeneous technologies operating bidirectionally—continuously adding, reducing, or modulating power flowing to the grid. By integrating DERs with the power grid, their service and value can be optimized (EPRI 2014). Effectively integrating DERs means greater operational complexity and requires a significant leap forward in grid design and engineering. Intelligent communication technologies, predictive analytics, and new networking, security, and interoperability protocols are necessary to optimize the power system and derive the full value from the technologies. Integrated operation of distributed energy resources can provide consistent power, reducing the need for baseload generators.

Disruptive Forces

The successful reduction of energy use through energy efficiency, energy conservation, and demand management means that utilities can no longer rely on steady growth in electricity sales that have historically driven investment in central station electric infrastructure. New energy management technologies are coming to market with the potential further to reduce load. More than 50 million smart meters were deployed in the U.S. by mid-2014 (IEI September 2014). With the integration of smart meters and other emerging technologies that increase connectivity, customers are finding new ways to monitor and manage energy consumption in real time. Google's acquisition of Nest, Apple, and Samsung's exploration of the home energy management sector suggests new areas of market competition for traditional utilities with a focus on achieving energy savings for customers.

DER growth is projected to be substantial. Innovation, improvements in energy technologies, and new materials will continue to sharpen the economics of DERs; the advent of new finance and business models will enable broader adoption of these technologies. Solar PV has the potential to reach retail or "socket" parity with utility service over time, in all areas including those with lower residential and commercial rates. In 2014, 600,000 solar systems were installed on homes and businesses (SEIA December 2014). The number may reach one million by the end of 2015. Capital markets are responding to perceived new growth opportunities with tax equity financing, project finance lending, and residential PV leasing models (EEI 2013). Competition in energy markets will increase with new energy product and service offerings like yieldcos[34], green bonds, and new financial models that enable procurement (BNEF 2015).

Another emerging trend is the growing demand from businesses, industries, and consumers for clean energy resources. Google, Facebook, Microsoft, Amazon, Walmart, Intel, and many other businesses have zero-carbon energy procurement goals. Businesses, hospitals, military bases, government agencies, and homeowners will increasingly self-generate their own clean power. Microgrids, capable of operating independently in an "island" mode to support the grid during storm events and outages, are beginning to power these critical infrastructure.

While the disruptive potential of DERs are substantial, so are the potential benefits. CHP plants can provide baseload power and heat energy, while other distributed energy resources can provide power to meet peak demand, supplemental power and remote power. They can also shape, balance and smooth loads while shaving peak demand. Because they are located close to load, DERs can help lower overall system cost by reducing transmission and distribution losses and deferring or avoiding new capital investment. DERs, are for the most part, low-carbon or zero carbon energy technologies, eliminating fuel costs or mitigating energy cost volatility. DERs are also capable of making the grid more reliable and resilient while improving power quality.

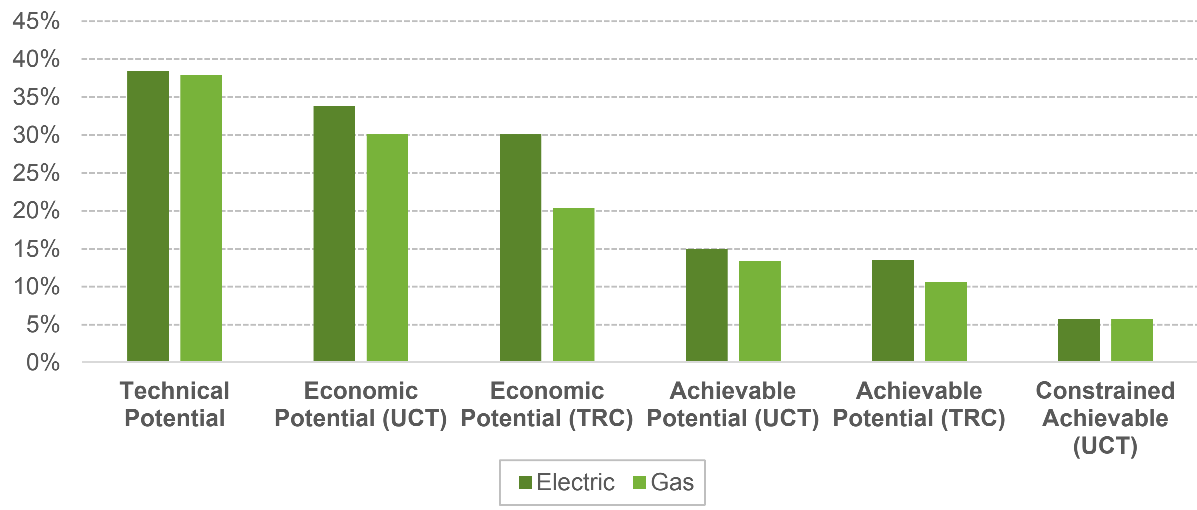
Potential for Savings through Energy Optimization

The MPSC worked collaboratively with DTE and Consumers to complete a 2013 study of energy-efficiency potential in the state of Michigan. The study provided a roadmap for policymakers and identified the energy-efficiency measures having the greatest potential savings and the measures that are the most cost effective. The study—conducted by the consulting firm GDS Associates—estimates the potential for energy-efficiency measures under several scenarios, including technical potential, economic potential, and achievable potential. See Exhibit 4.17 for additional information.

The study examined 1,417 electric energy-efficiency measures and 922 natural gas measures in the residential, commercial and industrial sectors combined. Overall, the achievable potential for electricity savings based on the UCT is 15.0 percent of forecasted kWh sales for 2023. The potential for natural gas savings based on the UCT is 13.4 percent of forecasted MMBtu sales for 2023 (GDS 2013).

[34] Publicly traded companies comprised mostly of operating renewable energy assets (BNEF February 2015).

EXHIBIT 4.17. Forecasted Electric and Gas Savings as a Percent of Statewide Sales in 2023



SOURCE: GDS Associates, Inc. November 5, 2013. Michigan Electric and Natural Gas Energy Efficiency Potential Study. Available at: http://www.dleg.state.mi.us/mpsc/electric/workgroups/mi_ee_potential_studyw_appendices.pdf. (accessed 3/24/15)

Potential for Renewable Energy Development in Michigan

Renewable generation has increased at an average rate of 1 percent per year since Michigan's RPS was implemented. The Renewable Energy Report released as part of Governor Snyder's Readying Michigan to Make Good Energy Decisions process included an evaluation of the potential for expanding the state's RPS. The report found Michigan could achieve a 30 percent RPS by 2035 without exceeding current surcharge caps. The report also noted that Wisconsin, Pennsylvania, Illinois, and Minnesota have RPSs with annual increases of 0.8 to 1.3 percent per year (Quackenbush 2013).

In April 2015, the Vermont Energy Investment Corporation (VEIC) released their final report—Michigan Renewable Resource Assessment—which estimates a bounded technical potential as well as projections for the cost and performance profiles expected over the next 15 years for utility scale onshore wind, solar photovoltaics, and central station biomass power (VEIC 2015). The full report is attached as Appendix M. The bounded technical potential estimates the amount of renewable generation available by time period considering limitations on annual growth rates, renewable resource base, land use, and siting restrictions. Exhibit 4.18 shows the estimated bounded technical potential generation for each of the renewable energy resources included in the report.

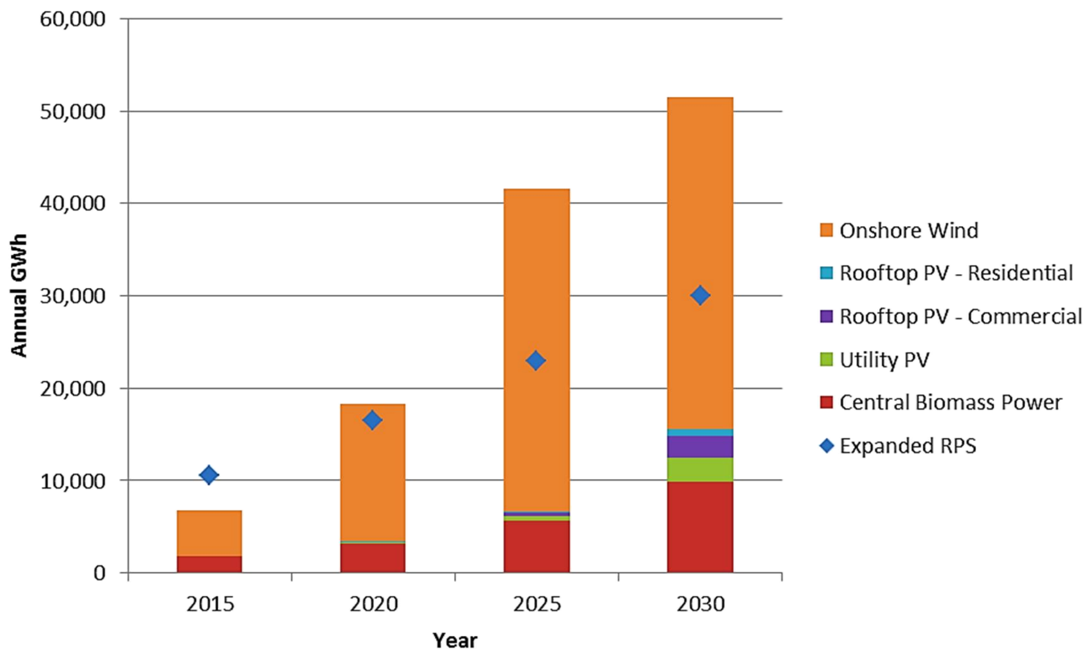
EXHIBIT 4.18. Bounded Technical Potential Estimated Generation

Annual Generation (GWh)	2015	2020	2025	2030
Onshore wind	4,882	14,897	34,971	36,000
Rooftop PV—residential	5	25	137	736
Rooftop PV—commercial	15	81	435	2,339
Utility PV	16	87	466	2,509
Central biomass power	1,814	3,198	5,635	9,931
Total	**6,732**	**18,288**	**41,645**	**51,514**

SOURCE: Vermont Energy Investment Corporation (VEIC). April 8, 2015. *Michigan Renewable Resource Assessment Final Report.* Available at: https://www.michigan.gov/documents/mpsc/VEIC_Renewables_Assessment_487864_7.pdf (accessed 4/29/15)

Exhibit 4.19, shows the amount of renewable energy required to achieve an expanded RPS that increases 1 percent per year starting at 10 percent in 2015.

EXHIBIT 4.19. Onshore Wind, Biomass Power, and Solar Potential Contributions to Meeting Expanded RPS (GWh)



NOTE: Illustrates the bounded technical potential under expanded renewable portfolio standard. Standard starts at 10 percent in 2015 and increases 1 percent annually through 2030.
SOURCE: Vermont Energy Investment Corporation (VEIC). April 8, 2015. *Michigan Renewable Resource Assessment Final Report.* Available at: https://www.michigan.gov/documents/mpsc/VEIC_Renewables_Assessment_487864_7.pdf (accessed 4/29/15)

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Appendix A

Transmission Projects: ITC

- The METC-ITC Transmission interface upgrade replaced 138/120 kV transformers at Genoa and Atlanta and replaced station equipment at Hemphill to improve transfer capability across the METC-ITC transmission interface by approximately 1,000 MW.
- The Jewell-Spokane project involved a 230 kV line conversion of approximately ten miles of 120 kV and approximately three miles of existing 345k kV to 230 kV to establish a new line. The project reduced congestion under imports from Ontario.
- The Simpson-Batavia 139 kV project involved the construction of 30 miles of new 138 kV line, adding another source into the southern METC area to alleviate overloads and support voltage stability.
- The Cobb Swamp rebuild near the Cobb Generating Station rebuilt the floodplain section of five circuits. The existing five individual H-frame single-circuit lines were built in the late 1950s and showed deterioration due to age and weather as well as approving site access to all transmission assets.
- The Caniff-Stephens cable replacement project replaced seven miles of 345 kV underground cables. The project improved reliability to Detroit area, due to the existing 345 kV cable's increasing failure rate.
- The Michigan Thumb Wind Zone Multi-Value Project involves the construction of approximately 140 miles of double-circuit 345 kV lines and four new substations that serve as a "backbone" to support the interconnection of renewable generation sources in the Thumb area of Michigan. The project is in the final stages of construction. This project allowed for reliable connection of much of Michigan's wind resources as well as allowing for the retirement of DTE's Harbor Beach Power Plant in 2013. Although Harbor Beach Power Plant was a higher cost generation facility as compared to others, prior to the construction of the project, the plant was necessary to maintain overall system reliability.

Appendix B

Transmission Projects: ATC

The remote nature of Michigan's Upper Peninsula, coupled with the small, rural population, has presented reliability challenges that ATC continues to address. ATC developed a measure called "Flow South" several years ago, which represents the import capacity into Michigan's Upper Peninsula. Since the development of Flow South, ATC has developed four major initiatives to increase transmission system capability to move power into or within the Upper Peninsula.

- The Northern Umbrella Plan will increase Flow South capability by as much as 300 MW under certain circumstances.
- The Energy-Collaborative Michigan projects dealt with limitations to the transmission system internal to the Upper Peninsula. These projects did not have an appreciable effect on Flow South. However, the Mackinac High Voltage Direct Current project provided an opportunity to more reliably manage flow into the Upper Peninsula and periodically obtain slightly higher overall flow into the area.
- The Bay Lake projects included the Holmes-Old Mead Road Project (MPSC approved in January 2014), and the North Appleton-Morgan Project (facilities under PSCW review by Wisconsin regulators). Both of these projects have received approval from MISO and are expected to increase Flow South capability by about 150 MW.
- The Northern Area Reliability Assessment is still being developed. This project would maintain the transmission system reliability provided by the third initiative while allowing Presque Isle Power Plant generation to eventually retire. A Flow South change has not been estimated, in part because the final solution is still subject to influence from a variety of factors. However, ATC expects that the Flow South increase for the fourth initiative could be roughly of the magnitude of the Presque Isle generation.

Overall, the projects from these first three initiatives can be expected to increase the Flow South capability by about 350 MW, when all projects are in service. Again, Flow South is just a single contingency measure, so there will be less capability available during some maintenance outages, just as there would have been less capability available during maintenance outages with the original system. Nevertheless, even during maintenance outages, the capability to move power into the Upper Peninsula will increase.

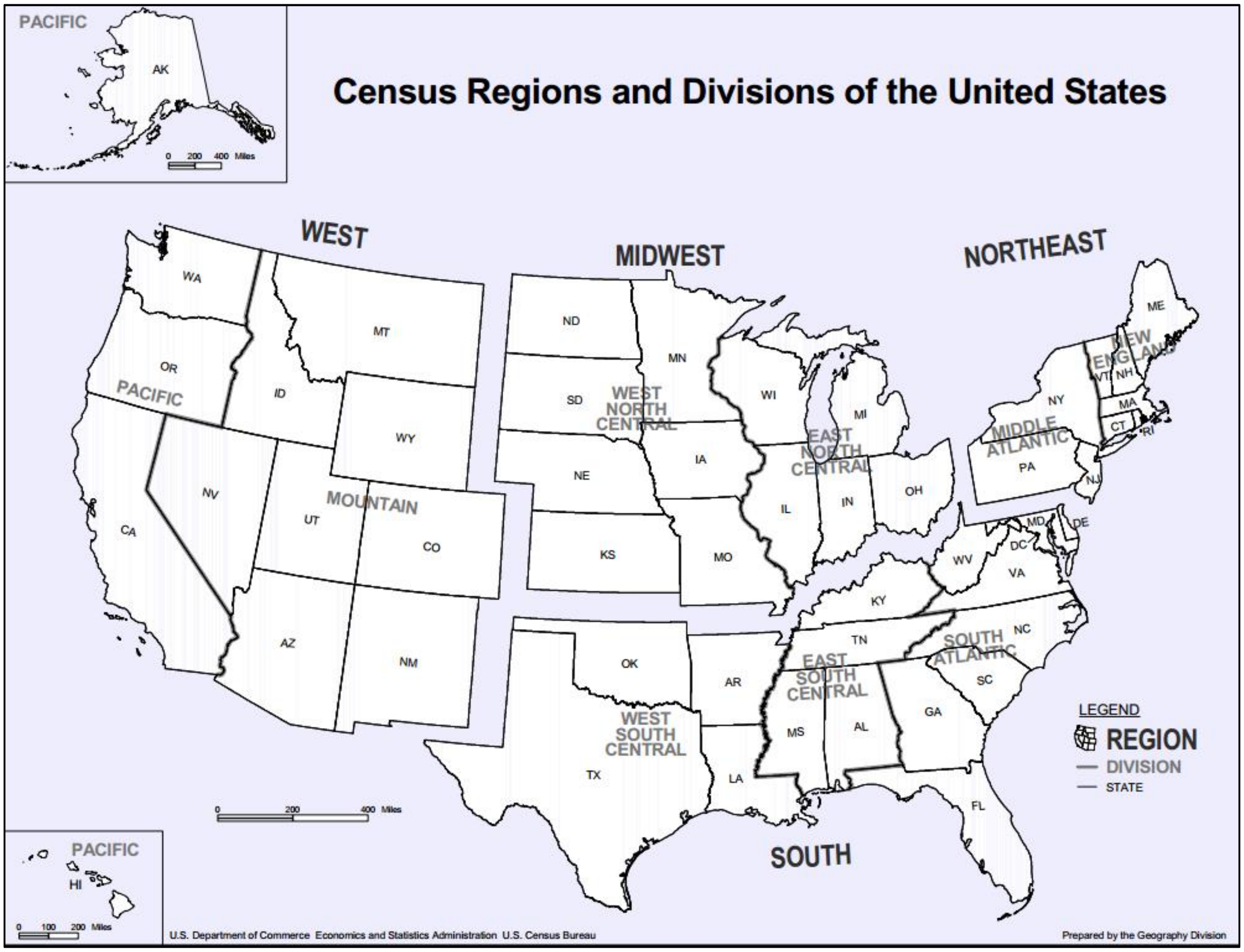
Appendix C

Transmission Projects: Indiana Michigan Power Company

- The DC Cook station connects Donald C Cook nuclear plant with the electric grid and is the main supply for AEP customers in the states of Indiana and Michigan. Improvements have been made to the 765 kV and 345 kV equipment, including circuit breakers and transformers, these were replaced due to age and condition.
- New 345 kV circuit breakers were installed to replace lines on the Benton Harbor Extra High Voltage system.
- The Benton Harbor station is critical 345 kV to meeting load requirement for southern Michigan. The project was completed in 2014 and allows for surgical sectionalizing of the Extra-High Voltage (EHV) lines to ensure continued reliability.
- Improvements to the Mishawaka Area include a second 138 kV circuit of approximately 18 miles in length increasing the capacity to a double circuit and the addition to construction of a 138 kV station. The project mitigated thermal (capacity) overloads identified during simulated 2014 summer peak. The project improved system efficiency by retiring lower voltage source station and serving the load from a higher voltage, thus reducing system losses.
- The Michiana Area Improvements Projects involved rebuilding approximately eight miles of 69 kV line and the construction of a 69 kV station. Additionally the project included two 138 kV stations and retirement of a 15-mile 345 kV line. The project mitigates low voltages and thermal overloads identified during simulated 2015 summer peak conditions
- The Benton Harbor, Hartford, and Watervliet Area Improvements project includes the construction of two miles of 138 kV line and a 138 kV station, in addition to the retirement of eight miles of 345 kV line plus a 345 kV and a 69 kV station. The project mitigates thermal overloads identified during simulated 2015 summer peak conditions
- The East Elkhart station, situated near Indiana-Michigan is a critical 345 kV station to meet load requirement for southern Michigan. Improvements made to the East Elkhart EHV lines include the installation of 345 kV circuit breakers which will replace line motor operated air brake switches (MOABs) in order to improve operational performance of the system. The project mitigates thermal overloads identified during simulated 2016 summer peak conditions
- The Corey-Pokagon Line project involves rebuilding approximately 25 miles of a 69 kV line as a double circuit 138 kV line, and construction of a 138 kV station is proposed. In addition, the project also mitigates low voltages identified during 2017 summer simulated conditions
- Improvements to the Sister Lakes Area system involve construction of approximately seven miles of 69 kV line, reconstruction of approximately ten miles of poor performing 345 kV line, and construction of two 69 kV stations is proposed. The project also mitigates low voltages identified during 2018 summer simulated conditions
- Additional Supervisory Control and Data Acquisition System (SCADA), Telecom, and Volt-VAR Regulation/Optimization (VVO) improve both system efficiency and reliability. The SCADA penetration for I&M's Michigan territory is still below average, but the company is undertaking several projects to enhance Michigan's transmission system SCADA capability.

Appendix D

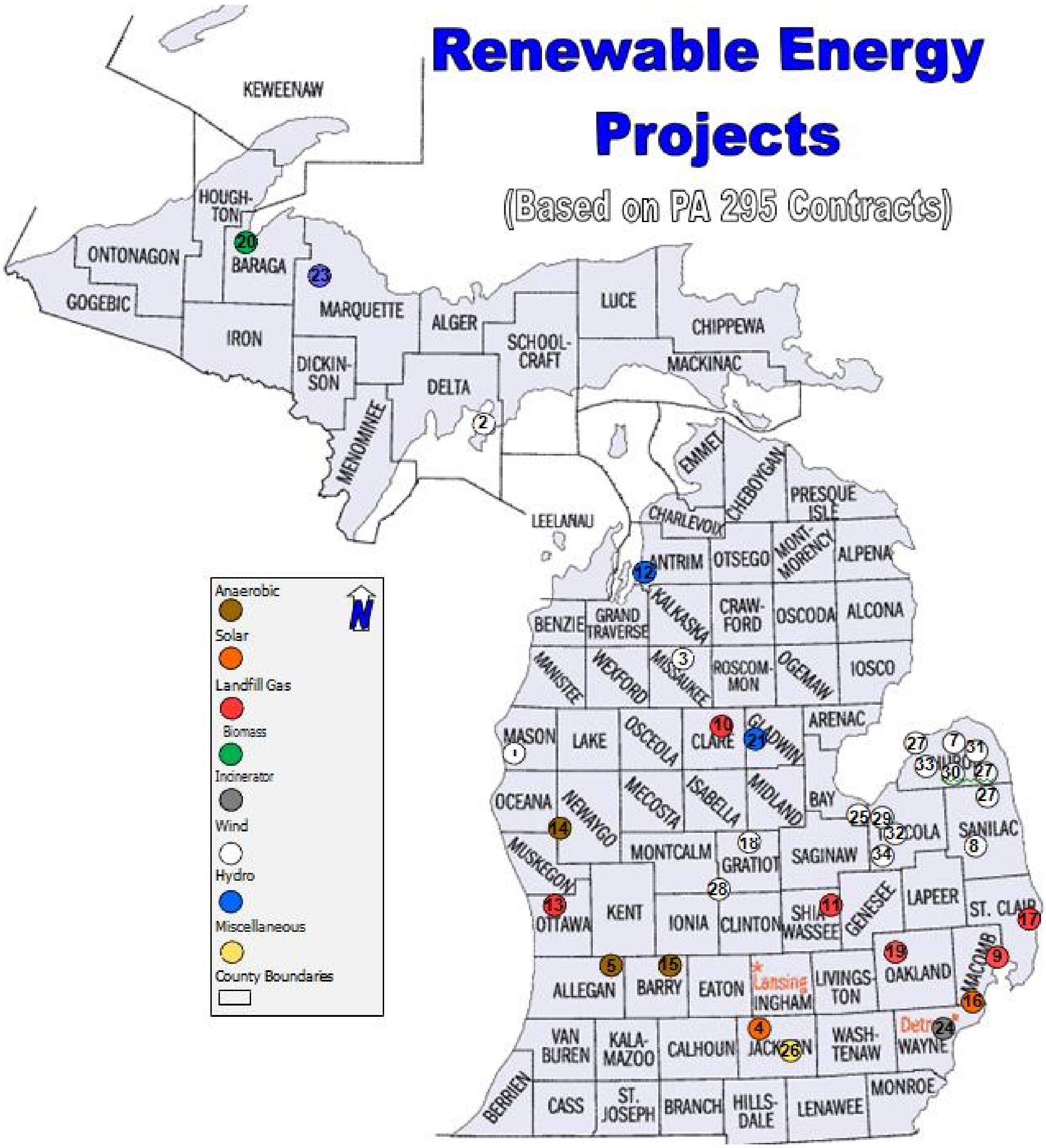
Census Regions and Divisions of the United States



SOURCE: U.S. Census Bureau. N.d. *Geographic Terms and Concepts - Census Divisions and Census Regions.* Available at: http://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf. (accessed 3/21/15)

Appendix E

Renewable Energy Projects Based on PA 295 Contracts



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Appendix F

Natural Gas Pipeline Capacity, Michigan 2014

2014 Pipeline State-to-State Capacity, **Delivered Out of Michigan**

Pipeline	State From	County From	State To	County To	Capacity (MMcf/d)
Panhandle Eastern	Michigan	Wayne	Ontario	Ontario	100
Great Lakes Gas Trans	Michigan	Chippewa	Ontario	Ontario	2,210
ANR Pipeline Co	Michigan	Cass	Indiana	Elkhart	1,567
ANR Pipeline Co	Michigan	Iron	Wisconsin	Florence	860
ANR Pipeline Co	Michigan	Lenawee	Ohio	Fulton	100
ANR Pipeline Co	Michigan	St. Clair	Ontario	Ontario	150
Vector Pipeline Co	Michigan	St. Clair	Ontario	Lambton	1,350
Bluewater Pipeline Co	Michigan	St. Clair	Ontario	Sarnia	250

2014 Pipeline State-to-State Capacity, **Delivered to Michigan**

Pipeline	State From	County From	State To	County To	Capacity (MMcf/d)
Northern Natural Gas Co	Wisconsin	Iron	Michigan	Gogebic	82
Panhandle Eastern	Ohio	Fulton	Michigan	Lenawee	960
Great Lakes Gas Trans	Wisconsin	Iron	Michigan	Gogebic	2,226
ANR Pipeline Co	Indiana	Elkhart	Michigan	Cass	1,520
ANR Pipeline Co	Ohio	Fulton	Michigan	Lenawee	932
ANR Pipeline Co	Wisconsin	Marinette	Michigan	Menominee	148
Trunkline Gas Co	Indiana	Elkhart	Michigan	St. Joseph	739
Vector Pipeline Co	Indiana	St. Joseph	Michigan	Berrien	1,350
Vector Pipeline Co	Ontario	Lambton	Michigan	St. Clair	1,350
Bluewater Pipeline Co	Ontario	Sarnia	Michigan	St. Clair	250

2014 Natural Gas Pipeline Capacity State-to-State Flows

State Inflow Capacity			State Outflow Capacity			State Net Inflow Capacity	
State To	State From	MMcf/d	State From	State To	MMcf/d	States	MMcf/d
Michigan	Indiana	3609	Michigan	Indiana	1,567	Michigan	2,970
	Ohio	1892		Ohio	100	Illinois	2,653
	Ontario	1600		Ontario	4,060	Indiana	2,207
	Wisconsin	2456		Wisconsin	860	Ohio	5,183
Michigan Total		**9,557**	**Michigan Total**		**6,587**	**Wisconsin**	**3,370**

SOURCE: U.S. EIA. December 31, 2014. U.S. state-to-state capacity. Available at: http://www.eia.gov/naturalgas/data.cfm#pipelines (accessed 4/17/15)

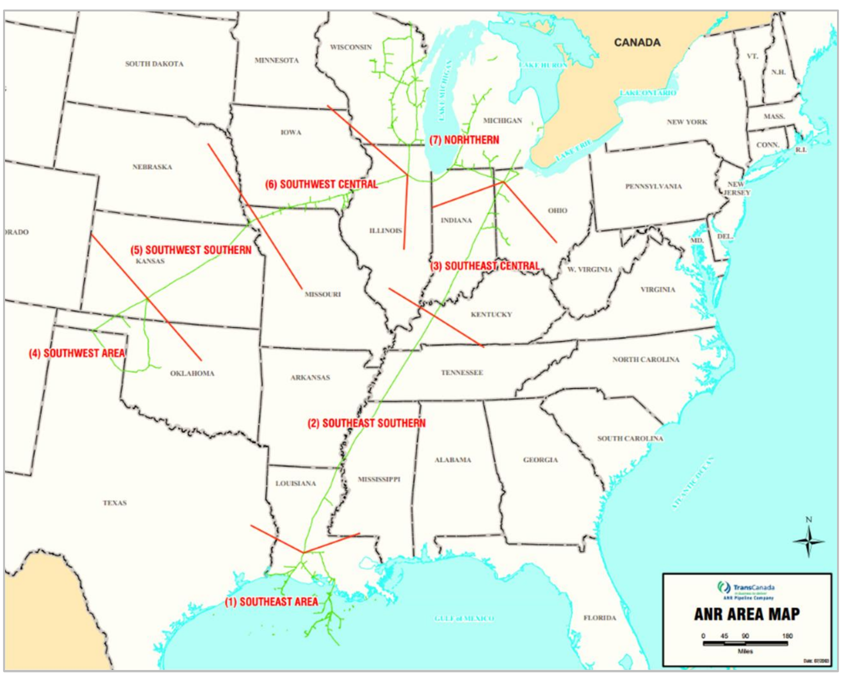
Natural Gas Pipeline Map

SOURCE: U.S. Energy Information Administration. November 2014. Michigan State Profile and Energy Estimates. Available at: http://www.eia.gov/state/?sid=MI. (accessed on 2/18/15)

Great Lakes Gas Transmission Company

SOURCE: Great Lakes Gas Transmission Company. n.d. *Pipeline Map.* Available at: http://www.glgt.com/pipeline/pipe_map.htm (accessed 5/12/15)

ANR Pipeline Company

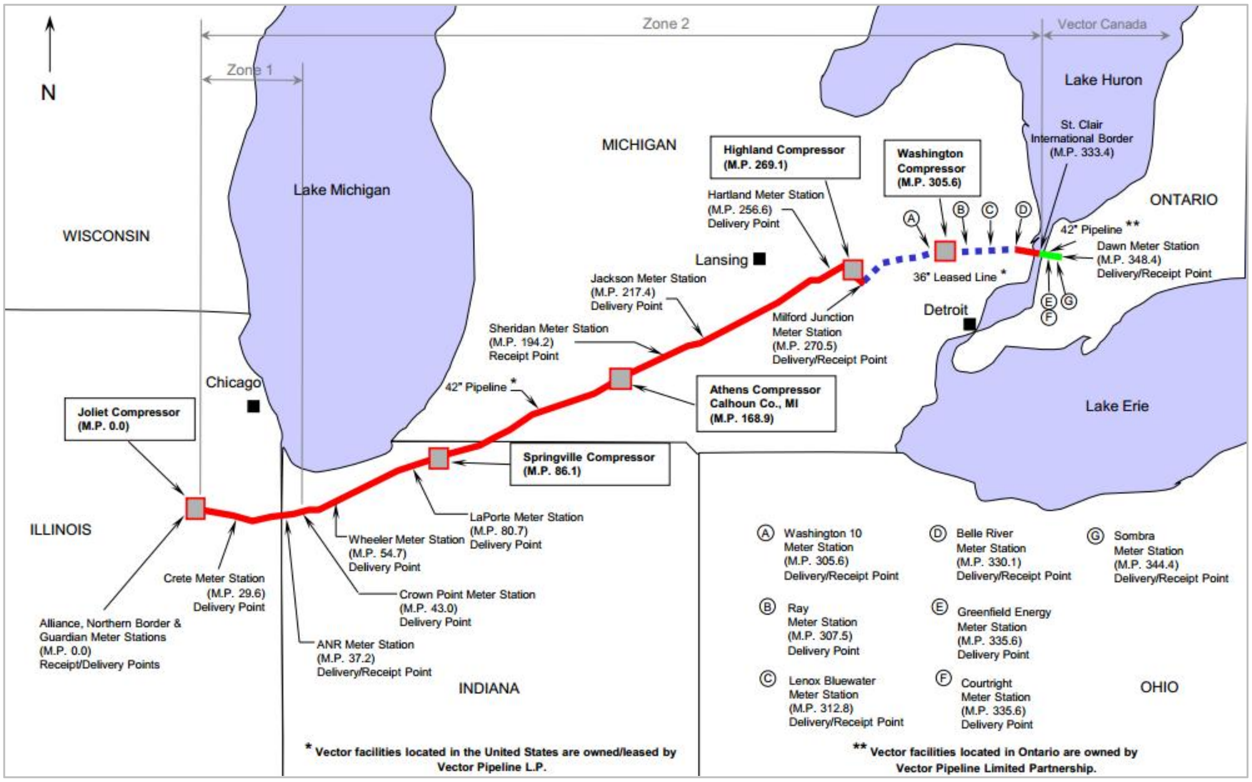


SOURCE: Trans Canada ANR Pipeline. December 31,2014. *Pipeline Map.* Available at: https://www.anrpl.com/company_info/ (accessed 5/15/15)

Trunkline Gas Company, LLC

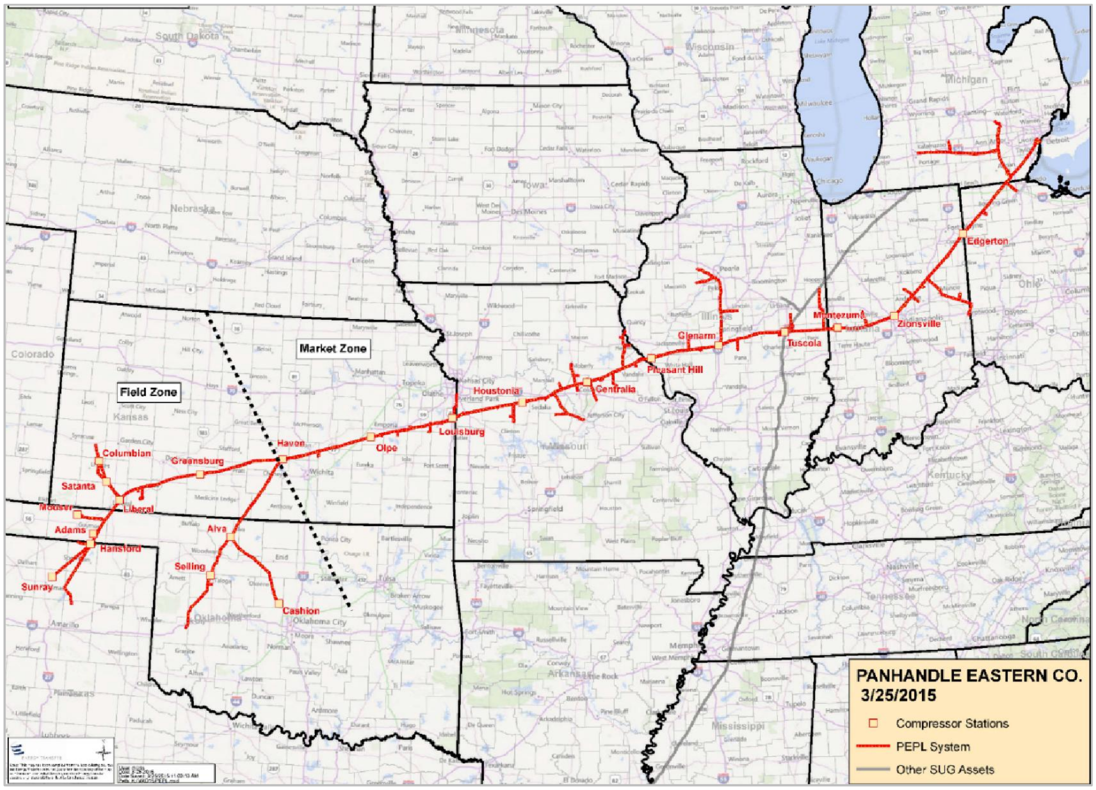
SOURCE: Trunkline Gas Company, LLC. March 19, 2015. *Maps.* Available at: http://tgcmessenger.energytransfer.com/ipost/TGC/maps/system-map (accessed 5/12/15)

Vector Pipeline

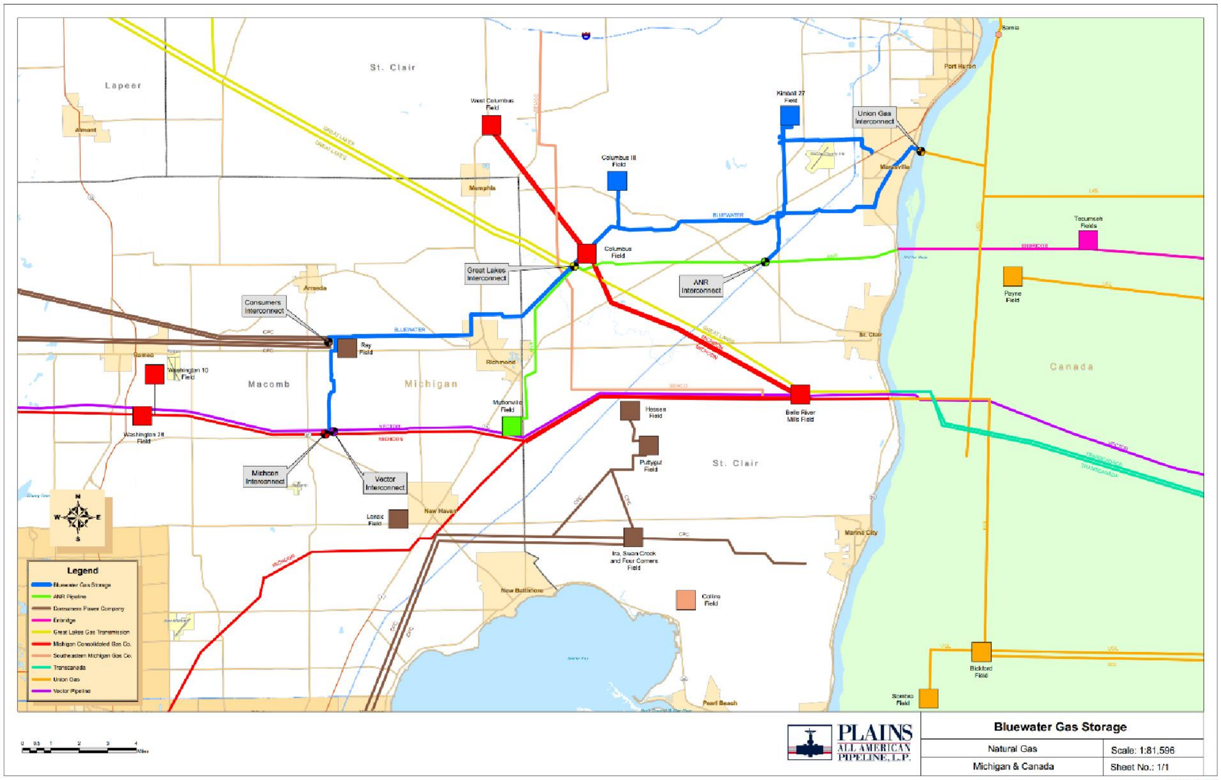


SOURCE: Vector Pipeline. n.d. *Vector Pipeline System Map.* Available at: http://www.vector-pipeline.com/WorkArea/downloadasset/6778/Vector-System-Map-4-08.aspx (accessed 5/12/15)

Panhandle EasterN Pipeline Company



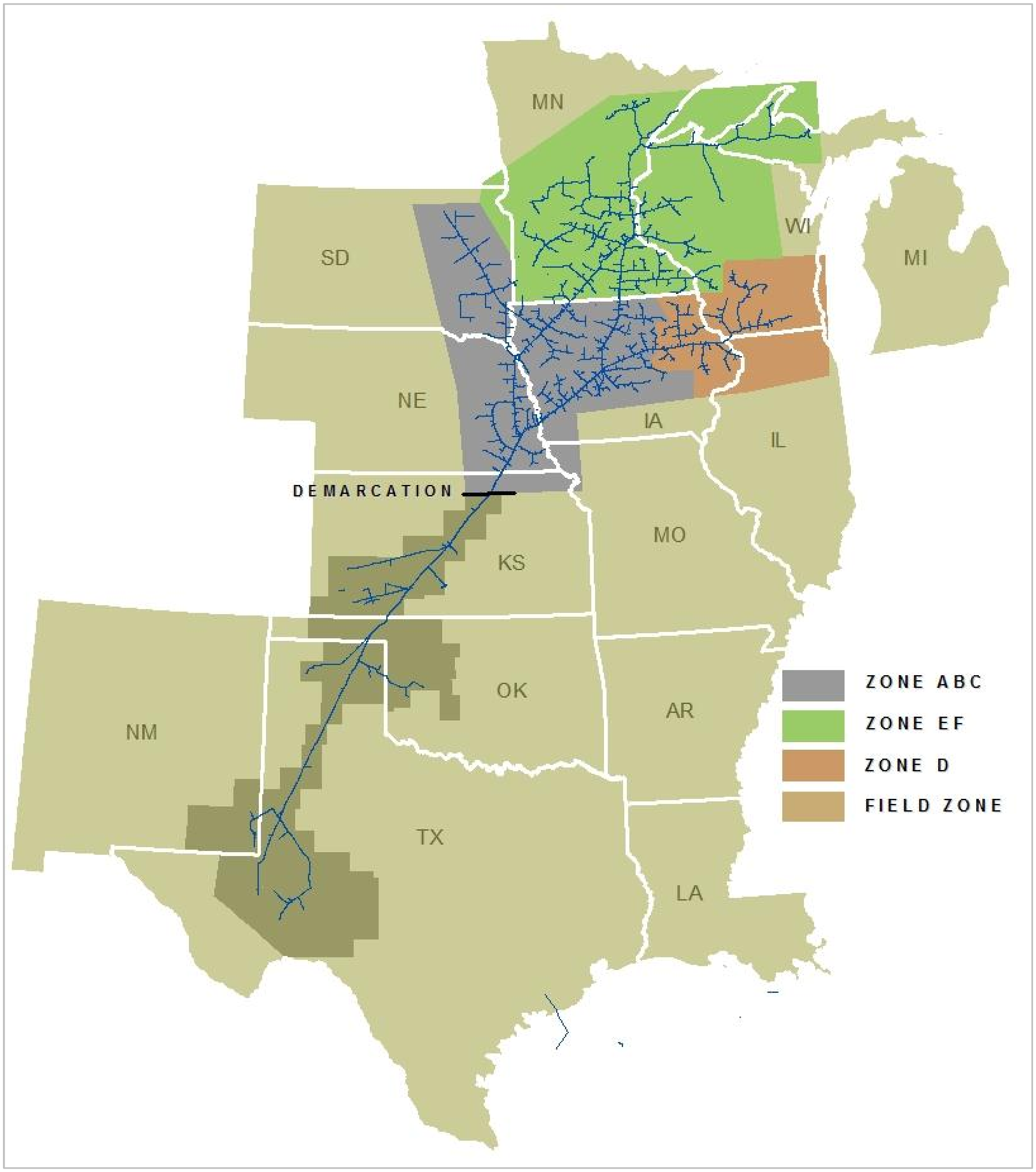
SOURCE: Panhandle Eastern Pipeline Company, LP. March 25, 2015. *Maps.* Available at: http://peplmessenger.energytransfer.com/ipost/PEPL/maps/system-map (accessed 5/12/15)



Area of detail

SOURCE: Plains All American Pipeline, LP. May 26, 2006. *Bluewater Map.* Available at: http://www.pnglp.com/images/uploads/content/Bluewater_Map.pdf (accessed 5/12/15)

Northern Natural Gas Company



SOURCE: Northern Natural Gas. n.d. *Northern Facilities.* Available at: http://www.northernnaturalgas.com/aboutus/Pages/PipelineMap.aspx#top (accessed 5/14/15)

Appendix G

Natural Gas Underground Storage

Underground Storage Fields Map

SOURCE: U.S. Energy Information Administration. November 2014. Michigan State Profile and Energy Estimates. Available at: http://www.eia.gov/state/?sid=MI. (accessed on 2/18/15)

Underground Natural Gas Storage, Michigan

Underground storage capacity for natural gas	1,079,424 (MMcf)
Underground storage capacity, working capacity	674,967 (MMcf)
Total number of existing storage fields	45
Number of fields, salt caverns	2
Number of fields, depleted fields	43
Working capacity, salt caverns	2,159 (MMcf)
Working capacity, depleted fields	672,808 (MMcf)

Appendix H

Emissions of Fee Subject Pollutants

In compliance with Title V of the Federal Clean Air Act of 1990, the State of Michigan operates an emission permitting system and issues Renewable Operating Permits (ROPs). Major emissions sources are subject to Title V.

A major source emits (or has the potential to emit) ten tons per year of any one hazardous air pollutant (HAP), 25 tons per year of any combination of HAPs, or 100 tons per year of any other regulated air contaminant (see Rule 211). Certain categories that have lower thresholds for an "area source" standard are also required to get an ROP. Facilities with ROPs are required to pay annual emission fees to the State of Michigan.

Annual Air Emissions from Electric Generating Units, 2013

Reported to the Michigan Air Emissions Reporting System, Maintained by the Michigan Department of Environmental Quality, Air Quality Division

					Fee Subject Pollutants, Emissions in tons								
SRN	OWNER	SOURCE NAME	CITY	ROP TYPE	CO	LEAD	HCL	NMOC	NOX	PM10	SO2	VOC	Total emissions
B1573	City Of Escanaba	Escanaba Power Plant	Escanaba	Major	12	0	12		17	0	105	0	134
B1833	City Of Marquette	Marquette Board Of Light & Power	Marquette	Major	71	0			321	0	404	5	730
B1966	TRAXYS NA	White Pine Electric Power LLC	White Pine	Major	6	0			87	16	258	1	362
B1976	Grand Haven Board of Light and Power	J.B. Sims Generating Station	Grand Haven	Major	21	0			208	2	175	3	388
B2132	Department of Municipal Service	Wyandotte Dept Muni Power Plant	Wyandotte	Major	75	0	34		181	12	139	4	370
B2185	Detroit Public Lighting Department	Detroit Public Lighting Department	Detroit	Major	0	0			2	0	0	0	2
B2357	Holland Board of Public Works	Holland BPW, Generating Station & WWTP	Holland	Major	11	0	6		369	2	563	1	941
B2647	Lansing Board of Water and Light	LBWL, Eckert, Moores Park & REO Cogeneration	Lansing	Major	315	0	490		1,437	51	2,453	31	4,462
B2795	DTE - Electric Company	DTE - Electric Company Colfax Peakers	Fowlerville	Major	0				5	0	0	0	5
B2796	DTE - Electric Company	St. Clair / Belle River Power Plant	Saint Clair	Major	2,065	0	543		17,777	60	54,898	244	73,522

Annual Air Emissions from Electric Generating Units, 2013 Reported to the Michigan Air Emissions Reporting System, Maintained by the Michigan Department of Environmental Quality, Air Quality Division													
					Fee Subject Pollutants, Emissions in tons								
SRN	OWNER	SOURCE NAME	CITY	ROP TYPE	CO	LEAD	HCL	NMOC	NOX	PM10	SO2	VOC	Total emissions
B2798	DTE - Electric Company	DTE - Electric Company Delray Power Plant	Detroit	Major	1				4	1	0	0	5
B2802	Detroit Edison Company	DTE Electric Company - Oliver Peaking Station	Oliver Twp	Major	0				3	0	0	0	3
B2803	DTE - Electric Company	DTE - Electric Company Placid Station	Springfield	Major	0				7	0	0	0	7
B2804	DTE - Electric Company	DTE - Electric Company Wilmot Peak	Kingston Twp	Major	0				6	0	0	0	6
B2805	DTE - Electric Company	DTE - Electric Company Hancock Peaker Station	Commerce Twp	Major	1				11	0	0	0	11
B2806	DTE - Electric Company	DTE - Electric Company Superior	Superior Twp	Major	0	0			0	0	0	0	0
B2807	Detroit Edison Company	DTE Electric Company - Putnam Peaking Station	Mayville	Major	0				6	0	0	0	6
B2808	DTE - Electric Company	DTE - Electric Company Northeast Station	Warren	Major	1	0			5	0	0	0	5
B2810	DTE - Electric Company	DTE - Electric Company RIVER ROUGE	River Rouge	Major	352	0	169		3,010	15	9,214	40	12,448
B2811	DTE - Electric Company	DTE - Electric Company Trenton Channel	Trenton	Major	500	0	192		4,024	91	19,992	61	24,360
B2812	DTE - Electric Company	DTE - Electric Company Conners Creek	Detroit	Major	0	0			0	0	0	0	0
B2814	Detroit Thermal LLC	Detroit Thermal Beacon Heating Plant	Detroit	Major	29	0			69	3	0	2	74
B2815	DTE - Electric Company	DTE - Electric Company Harbor Beach Power Plant	Harbor Beach	Major	6	0	31		149	2	308	1	491
B2816	DTE - Electric Company	DTE Electric Company - Monroe Power Plant	Monroe	Major	2,137	0	1,540		15,436	237	43,765	256	61,234

Annual Air Emissions from Electric Generating Units, 2013 Reported to the Michigan Air Emissions Reporting System, Maintained by the Michigan Department of Environmental Quality, Air Quality Division													
					Fee Subject Pollutants, Emissions in tons								
SRN	OWNER	SOURCE NAME	CITY	ROP TYPE	CO	LEAD	HCL	NMOC	NOX	PM10	SO2	VOC	Total emissions
B2835	Consumers Energy Company	J. H. Campbell Plant	West Olive	Major	1,222	0	93		6,007	150	23,628	147	30,025
B2836	Consumers Energy Company	B. C. Cobb Plant	Muskegon	Major	265	0	54		2,220	218	7,043	32	9,567
B2838	Veolia Energy, NA.	Veolia Energy Grand Rapids, LLC	Grand Rapids	Major	35	0			72	3	0	2	77
B2840	Consumers Energy Company	Consumers Energy Karn-Weadock Facility	Essexville	Major	646	0	75		3,548	221	15,490	76	19,410
B2846	Consumers Energy Company	J.R. Whiting Co	Erie	Major	255	0	21		2,202	802	5,732	30	8,787
B2918	Consumers Energy Company	Consumers Energy Thetford Combustion Turbine Plant	Mount Morris	Major	1				6	0	0	0	6
B2934	Entergy Nuclear Palisades, LLC	Palisades Nuclear Plant	Covert	Major	1	0			6	7	0	0	13
B2942	Consumers Energy Company	Consumers Energy Gaylord Combustion Turbine Plant	Gaylord	Major	3				11	0	0	0	11
B3012	Detroit Thermal LLC	Detroit Thermal Blvd Heating Plant	Detroit	Sm Opt Out	0	0			0	0	0	0	0
B4001	Lansing Board of Water and Light	LBWL, Erickson Station	Lansing	Major	150	0	278		1,320	5	3,903	18	5,524
B4252	Indiana Michigan Power Company	AEP Cook Nuclear Plant	Bridgman	Sm 208a	2	0			9	0	0	0	9
B4260	Traxys NA	L'Anse Warden Electric Company LLC	L'Anse	Major	162	0			270	12	358	5	645
B4261	Wisconsin Electric Power Company	WISCONSIN ELECTRIC POWER COMPANY	Marquette	Major	310	0			3,556	21	6,001	37	9,615
B4321	Detroit Edison Company	The DTE Electric Company - Fermi Energy Center	Newport	Major	4	0			25	1	0	0	26

Annual Air Emissions from Electric Generating Units, 2013

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					Fee Subject Pollutants, Emissions in tons								
SRN	OWNER	SOURCE NAME	CITY	ROP TYPE	CO	LEAD	HCL	NMOC	NOX	PM10	SO2	VOC	Total emissions
B5421	Wolverine Power Supply Cooperative Inc.	Vandyke Generating Plant	Dorr	Major	2				7	0	0	0	7
B6145	DTE - Electric Company	DTE - Electric Company Greenwood Energy Center	Avoca	Major	133	0			198	16	2	9	225
B6527	Midland Cogeneration Venture	Midland Cogeneration Venture	Midland	Major	437				1,595	120	3	43	1,761
B6553	Upper Peninsula Power Company c/o WPSR	UPPCo Portage Station	South Range	Major	0	0			1	0	0	0	1
B6611	Michigan South Central Power Agency	MI SO CENTRAL POWER AGENCY	Litchfield	Major	24	0			275	3	489	3	770
B7287	City of Sturgis	Sturgis Municipal Power Plant	Sturgis	Major	0				3	0	0	0	3
B7536	Hillsdale Board of Public Utilities	HILLSDALE CITY OF PUBLIC UTILITIES	Hillsdale	Major	0				0	0	0	0	0
B7977	Zeeland Board Of Public Works	Zeeland Board Of Public Works	Zeeland	Major	1				5	0	0	0	5
C6230	City of Marshall	Marshall City, Electric Powerplant	Marshall	Sm Opt Out	1				3	0	0	0	3
M4764	Ford Motor Company	Ford Motor Co Elm Street Boilerhouse	Dearborn	Major	29	0			111	5	0	4	120
M4854	Wolverine Power Supply Cooperative Inc.	Sumpter Generating Plant	Belleville	Major	16				16	3	0	1	20
N0890	GDF Suez Energy North America, Inc.	Viking Energy of Lincoln, LLC	Lincoln	Major	123	0			190	37	161	1	389
N1160	Viking Energy of McBain LLC	Viking Energy of McBain	McBain	Major	139	0			211	56	209	2	478
N1266	Hillman Power Company L.L.C.	Hillman Power Co	Hillman	Major	352	0			206	18	88	5	317
N1395	Cadillac Renewable Energy Limited Partnership	Cadillac Renewable Energy Facility	Cadillac	Major	303	0			211	21	71	8	311

Annual Air Emissions from Electric Generating Units, 2013

Reported to the Michigan Air Emissions Reporting System, Maintained by the Michigan Department of Environmental Quality, Air Quality Division

					Fee Subject Pollutants, Emissions in tons								
SRN	OWNER	SOURCE NAME	CITY	ROP TYPE	CO	LEAD	HCL	NMOC	NOX	PM10	SO2	VOC	Total emissions
N1685	T.E.S. Filer City Station Limited Partnership	TES Filer City Station	Filer City	Major	260	0			1,306	57	527	4	1,894
N1784	ADA COGEN LIMITED PARTNERSHIP	ADA COGENERATION LIMITED PARTNERSHIP	Ada	Major	46	0			141	5	1	0	147
N2388	Grayling Generating Station LTD PTNR	Grayling Generating Station LTD PTNR	Grayling	Major	385	0			172	2	10	4	188
N2586	Holland Board of Public Works	Holland BPW, 48th Street Peaking Station	Holland	Major	11	0			6	1	0	0	7
N2803	Lyon Development, Inc.	Lyon Development, Inc.	New Hudson	Major	15			6	6	0	4		16
N3570	GENESEE POWER STATION LIMITED PARTNERSHIP	GENESEE POWER STATION LIMITED PARTNERSHIP	Flint	Major	157	0			152	61	80	28	321
N3655	Bronson Healthcare Group	Bronson Battle Creek	Battle Creek	Minor	3	0			4	0	0	0	4
N4975	Michigan Power Limited Partnership	Michigan Power Limited Partnership	Ludington	Major	35	0			149	33	1	6	189
N5760	Wolverine Power Supply Cooperative Inc.	Wolverine Power Supply - Hersey	Hersey	Sm Opt Out	3				5	0	0	0	5
N5890	GRANGER ELECTRIC COMPANY	Ottawa Generating Station	Coopersville	Major	223				120	10	4	33	167
N6358	Detroit Thermal LLC	Detroit Thermal Henry Heating Plant	Detroit	Sm Opt Out	0	0			0	0	0	0	0
N6521	Consumers Energy Company	Zeeland Generating Station	Zeeland	Major	177				118	19	3	5	145

Annual Air Emissions from Electric Generating Units, 2013

Reported to the Michigan Air Emissions Reporting System, Maintained by the Michigan Department of Environmental Quality, Air Quality Division

					Fee Subject Pollutants, Emissions in tons								
SRN	OWNER	SOURCE NAME	CITY	ROP TYPE	CO	LEAD	HCL	NMOC	NOX	PM10	SO2	VOC	Total emissions
N6526	CMS Generation Michigan Power L.L.C.	CMS Generation, Livingston Generating Station	Gaylord	Major	35				30	1	0	0	31
N6626	AlphaGen Power LLC	Jackson Power Company, LLC	Jackson	Major	188				236	4	2	0	242
N6631	CMS Energy Corp.	Dearborn Industrial Generation	Dearborn	Major	72	0			341	49	721	3	1,114
N6731	CMS Generation Michigan Power L.L.C.	CMS Generation Kalamazoo River Generating Station	Comstock Twp	Major	2				1	0	0	0	1
N6767	New Covert Generating Company, LLC	New Covert Generating Company, LLC	Covert	Major	46	0			45	64	4	7	120
N6833	Wolverine Power Supply Cooperative Inc.	Wolverine Power, Gaylord Generating Station	Gaylord	Major	6				32	1	0	0	33
N6873	Renaissance Power LLC	Renaissance Power LLC	Carson City	Major	60				39	4	1	4	48
N7113	Michigan Public Power Agency	Michigan Public Power Agency	Kalkaska	Major	12				10	1		0	11
N7786	DTE Pontiac North, LLC	DTE Pontiac North, LLC	Pontiac	Major	0	0							0
N8004	Landfill Energy Systems	SUMPTER ENERGY ASSOCIATES	Lenox Twp	Major	207				128	8	44	20	200
P0222	C&C Energy LLC	C&C Energy LLC	Marshall	Major	44				19	4	1	0	24
P0262	DTE Biomass Energy	Blue Water Renewables	Smiths Creek	Major	94				16	10	7	20	53
P0264	North American Natural Resources	North American Natural Resources Inc.	Zeeland	Major	3				2	0	0	0	2
P0375	Lowell Light & Power	Lowell Light & Power (LL&P)	Lowell	Sm Opt Out	0				0	0		0	0
P0426		Adrian Energy Associates LLC	Adrian	Major	58				31	2	2	3	38
Total					**12,361**	**0**	**3,538**	**6**	**68,527**	**2,547**	**196,864**	**1,209**	**272,691**

Appendix I
Resource Adequacy Operations

MISO Resource Adequacy Strategic Intent and Desired Business Outcomes

- MISO Strategic Intent
  - Stakeholders and MISO achieve confidence that the MISO region will be resource adequate in all time horizons.
    - For system planning time horizons, adequacy is defined as loss of firm load during any period of the year no more often than one day in ten years.
- MISO Desired Business Outcomes
  - Resource adequacy (RA) processes support stakeholders in achieving resource adequacy in accordance with state statutes and regulation.
  - MISO and stakeholder confidence that resource adequacy will be achieved in all time horizons.
  - MISO and stakeholder confidence in MISO's resource adequacy assessments.
  - MISO has provided sufficient transparency and market mechanisms to stakeholders to allow for mitigation of potential shortfalls.

MISO Resource Adequacy Principles

Load serving entities, with oversight by the states as applicable by jurisdiction, are responsible for their resource adequacy.

1. Resource adequacy processes must ensure confidence in resource adequacy outcomes in all time horizons.
2. MISO will work with stakeholders to ensure an effective and efficient resource adequacy construct that permits appropriate consideration of all eligible internal and external resources and resource types and recognition of legal/regulatory authorities and responsibilities.
3. MISO will determine adequacy at the regional and zonal level and provide appropriate regional and zonal resource adequacy transparency and awareness for multiple forward time horizons.
4. MISO will administer and evolve processes in a manner that provides transparency and reasonable certainty, appropriately protects individual market participant proprietary information and that supports efficient stakeholder resource and transmission investment decisions.
5. MISO's resource planning auction and other processes will support multiple methods of achieving and demonstrating resource adequacy, including self-supply, bilateral contracting and market-based acquisition (MISO August 2014).

MISO Resource Adequacy Construct

Rules governing the current MISO resource adequacy construct are set out in the Resource Adequacy Business Practices Manual (BPM), which is the implementation of the MISO Tariff's Module E on resource adequacy as approved by the Federal Energy Regulatory Commission (FERC).

The focus of MISO's RA construct is on the longer-term planning margins that are used to provide sufficient resources to reliably serve load on a forward-looking basis. In the real-time operational environment, only resources dedicated to meet demand—including resources to meet the Planning Reserve Margin Requirement (PRMR)—have an obligation to be available to meet real-time customer demand and contingencies. The resources used to achieve long-term RA are called planning resources (PRs), and consist of capacity resources, load modifying resources and energy efficiency resources. MISO coordinates with LSEs to determine the appropriate PRMs for the MISO region based upon the probabilistic analysis of available planning resources being able to reliably meet each LSE's forecasted load requirement for each month of the planning year (MISO April 24, 2014).

The MISO RA construct includes an annual RA auction that establishes a market clearing price, called the MISO Planning Resource Auction. The MISO RA construct also includes provision for LSEs to choose to self-schedule their resources in the auction and also to "opt-out" of participation in the auction entirely by providing resource plan to meet their obligations.

MISO Planning Resource Auction

The MISO Planning Resource Auction (PRA) serves several purposes, all related to making sure that an adequate supply of resources—not an excess supply—is available to meet demand. One purpose of the auction is to determine a market-based value attached to having resources located in certain geographical areas. MISO is required via a FERC order to construct a resource adequacy approach that takes resource location into account and determines a value for such locations using a market-based approach. Another purpose of the auction is to determine—and place a value upon—any congestion related to the different locations of capacity and load. While transmission congestion is evaluated in the energy and ancillary services market, such congestion is related to more narrowly defined issues. The auction identifies congestion related to capacity—based upon issues that reflect annual peak conditions as opposed to conditions occurring throughout the year.

Key Auction Elements

The PRA considers available resources with loads on a zonal basis. Key elements related to the auction include the following:

- Annual peak demand forecasts, prepared by LSEs (electric distribution Companies (EDCs) in retail choice states) and is for the total demand of their customers at the time of MISO's annual summer peak
- Transmission limitations determined from system engineering studies to allow the maximum amount of low cost resources to provide service
- Local clearing requirements indicating the amount of capacity that must be secured from resources within each zone to meet the reliability standard
- Single, sealed-bid auction style designed to minimize the ability for participants to signal or game the auction, while at the same time providing efficient market-clearing prices

This voluntary annual capacity auction allows market participants to achieve resource adequacy more economically, and its enhanced market-based design allows for greater transparency. The location-specific approach used in the PRA provides efficient price signals to encourage the appropriate resources to participate in the locations where they provide the most benefit. This methodology creates a variety of options for LSEs to obtain the resources required to meet their Planning Reserve Margin Requirement, including fixed resource adequacy plans, bilateral transactions, self-scheduling, capacity deficiency payments, and auction purchases (MISO April 2014).

Self-scheduling Provision

This feature of the proposed resource adequacy construct gives the LSE the flexibility to use its resources to meet all or a portion of their load requirements in the auction. The mechanism used to do this netting of resources and load in the auction is called a self-schedule. The LSE has the flexibility to self-schedule all or a portion of their needs and acquire their remaining resource needs through the Planning Resource Auction. These self-schedules are not subject to the economics of the auction.

MISO has nine zones within the footprint to ensure that resources can be reliably delivered to the load. These zones are called local resource zones (LRZs). There may be positive or negative economic impacts when load and resources are located in different zones. LSEs consider the following scenarios related to self-scheduling:

- Planning resources and load in the same zone have no price effect on the LSE.
- If the planning resource has existing firm transmission rights to deliver resources to a load in another zone then MISO will grant the LSE a financial hedge (grandmother agreement), and there will be no price effect on the LSE. These grandmother agreements were granted as an interim solution and are being phased out. There is the potential for MISO to begin developing new concepts or products designed to allow the hedging of interzonal price differences.
- Currently, zones with price differences are subject to zonal deliverability charges (ZDCs) based upon the price difference between zones. ZDCs are incurred when LSEs elect to use resources in one zone to serve load obligations in a different zone, and there is a price differential between those zones.
- LSEs with planning resources located in zones with a higher clearing price than the LSE's load will receive a net benefit.
- LSEs with planning resources located in zones with a lower clearing price than the LSE's load will pay for the congestion through a higher price.
- New planning resources will be eligible for a hedge against congestion in the auction if the LSE invests in new or upgraded transmission to serve the LSE's load in a different zone.

Opt-out Provision

MISO’s resource adequacy construct provides MISO LSEs the ability to use the self-scheduling provision or use in the alternative, an opt-out provision, to meet their PRMR (load forecast plus reserve margin). Both provisions are designed to allow the LSEs to remain doing what they do today to satisfy their resource planning requirements. One provision works in conjunction with the PR auction (self-scheduling) while the other allows LSEs to forego the auction and opt-out.

LSEs that choose to participate under the "opt-out" provision can choose between the following options:

1. opt-out of the capacity auction by submitting a fixed resource adequacy plan (FRAP):
   a. FRAP will identify resources for which an LSE has ownership or contractual rights that will be relied upon to meet the LSE's PRMR.
   b. FRAP resources must qualify under the new MISO qualification procedures developed for auction (similar to qualification procedures that are in current use).
   c. If the FRAP does not cover all the PRM requirements as specified by MISO, then the LSE must procure any shortfall through the annual capacity auction.
   d. Any excess capacity beyond the needs of the LSE to meet its own requirements must be offered into the auction, under an approach in which any new resources would be required to be offered into the auction and thus subject to MOPR provisions.

2. Any market participant can also fully or partially self-schedule through the annual auction (this means biding in existing resources into the auction at a zero price to ensure they clear).

One important note on the FRAP opt-out provision relates to resources owned by an LSE that are outside of its local resource zone. Because one of the purposes of the MISO PRA is to allocate (by zonal price differences) the transmission transfer capability between these zones, MISO has established a zonal deliverability charge based on the differences in the auction clearing prices in the various local resource zones that is charged to an entity using the opt-out option that is taking credit for resources being brought in from outside the local resource zone.

Resource Adequacy Standards

MISO determines the PRM for each LSE through a multifaceted study process, and publishes the results by November 1 prior to the planning year in question. A key component of the PRM determination process is a probabilistic analysis, referred to as the loss of load expectation (LOLE) study. The LOLE process first determines the probability, on the peak hour of each day, that there will be insufficient planning resources to meet the projected load at that hour. This daily probability is referred to as the loss of load probability (LOLP). The sum of LOLP's on the peak hour of each day in the planning year yields the LOLE, which is the expected number of hours per year that there would be insufficient PR to meet the expected load. The LOLE is typically constrained to a value of one day in ten years, or approximately 0.000274 hours per year.

- Loss of load probability
  - Probability that there will be insufficient PR on the peak hour of each day.
- Loss of load expectation
  - Expected number of hours per year that there will be insufficient PR to meet load.
  - One day/ten years

MISO coordinates with all LSEs to ensure that they have sufficient PRs to ensure they will not violate the LOLE criterion, as explained above. The amount of PRs above forecasted load necessary to maintain the one day in ten years LOLE standard constitutes the PRM for a given region.

The PRM that is calculated in the LOLE study is established on an installed capacity (ICAP) basis. The ICAP PRM value is subsequently adjusted down based on the system average forced outage rate, yielding a PRM that is calculated on an unforced capacity (UCAP) basis. There are two types of forced outage rates utilized in this transformation:

- EFORd
  - Equivalent demand forced outage rate
    - Measure of the probability that a generating unit will not be available due to forced outages/de-ratings at a time in which the unit has been called upon to generate electricity
- XEFORd
  - Equal to EFORd, but calculated by excluding the causes of outages that are outside of management control (OMC)

The PRM requirement is set to meet the forecasted LSE system requirements multiplied by (1 + PRM UCAP). This requirement tells each individual LSE the amount of PRs they must have (on a UCAP basis) to meet their load without violating the LOLE reliability criterion.

The only entity other than MISO that may establish a PRM is a state utility commission (MISO April 2014). If a state establishes a minimum PRM for any LSE in their jurisdiction, the state-set PRM would be adopted by MISO for all affected LSEs. A state may choose to evoke its own PRM standard if it disagrees with the MISO calculation, or under extenuating circumstances.

EXHIBIT 1. MISO Local Resource Zone 7 (Lower Peninsula of Michigan) PRM UCAP (MISO November 1, 2014).

	PY 2015–2016	PY 2016–2017	PY 2017–2018	PY 2018–2019	PY 2019–2020
PRM UCAP %	7.10%	7.10%	7.20%	7.10%	7.10%

PJM

PJM is a regional transmission organization (RTO) that manages the electric transmission system in parts or all of13 states and the District of Columbia. In the state of Michigan, PJM manages the transmission system owned by Indiana Michigan Power Company (I&M), an operating subsidiary of American Electric Power (AEP).

Load Forecasts

Since 2006, PJM has produced its own independent load forecast. Prior to that date, PJM relied on its members to provide such forecasts. Although PJM members now actively participate in discussions and modeling of such forecasts, the final annual load forecast is determined by PJM.

PJM's load forecasts are not developed by state but instead are developed by transmission owner zone, which for Michigan is the AEP zone. The economic inputs PJM uses to develop load forecasts are the number of households, population, personal income, nonmanufacturing employment, United States gross domestic product and gross metropolitan product (GMP). However, PJM does not use any GMPs for Michigan. The weighting of each economic input is customized to each zone based on the zone's mix between residential, commercial, and industrial load. PJM makes extensive use of data and projections furnished to it by Moody's Analytics.

In addition to economics, weather is the other major influence on PJM loads. PJM's load forecast model uses 40 years of weather history to develop hundreds of weather scenarios. A load forecast is produced for each of these scenarios and then the median (or "50/50") forecast for the annual peak day is defined to be the peak demand forecast for the year. The projected load growth in PJM and elsewhere has slowed considerably since the Great Recession that began in 2008. The forecast annualized load growth rate for the AEP zone is projected to be 0.8 percent for the 2014–2024 period, slightly below the overall PJM load growth projection of 1.0 percent per year. The load forecasts not only help with determining the amount of capacity to be acquired in the annual base residual and subsequent incremental capacity auctions but are also critical in assessing the need for enhancements of the PJM managed transmission system. The load forecasts are determined for 15 years into the future. PJM's Load Analysis Subcommittee of the PJM Planning Committee is one of the primary stakeholder groups that helps develop the load forecast.

Reserve Margin Requirement

The reserve margin requirement is the result of studies completed by PJM following the industry guidelines and standards for reliability established by the North American Electric Reliability Corporation (NERC) and Reliability First Corporation (RFC) using the traditional one day in ten year loss of load probability reliability measurement. The study results are reviewed through the PJM stakeholder process but the official reserve requirement is approved by the PJM Board of Managers. The reserve requirement can change from year to year due to such factors as load forecast uncertainty, available emergency assistance from adjacent regions and changes in generator performance. The reserve requirements for the five upcoming delivery years are as follows: 16.2 percent, for the 2014/2015 delivery year and 15.7 percent for the four subsequent delivery years.

Other Considerations

In determining whether PJM and its load serving members will be able to meet customer loads during the three upcoming delivery years, it is necessary to determine how much and where demand response and energy-efficiency initiatives will be available, the amount and location of new and retiring generation facilities and the potential for and realistic amount of imports deliverable from neighboring regions. These and other considerations are included on the Graph.

Reliability Pricing Model (RPM)

RPM is a multi-auction structure designed to procure resource commitments to satisfy the unforced capacity obligation in the PJM footprint three years into the future. The base residual auction occurs in May three years in advance of the delivery year and the incremental auctions occur several months in advance of the delivery year to procure additional resource commitments reflecting changes in market dynamics that are known prior to the beginning of the delivery year. Resources within and outside the PJM footprint can participate in the RPM auction, although prior to the beginning of the delivery year resources external to PJM must identify specific delivery paths and secure firm transmission service into PJM.

From other PJM sources:

The key design parameters of RPM are:

- Base residual and incremental auctions that procure capacity and adjustments to capacity obligations on a forward basis
- LDAs and locational capacity prices that are able to reflect the greater need for capacity in import-constrained areas
- Provisions that allow demand-side resources and new transmission projects to compete with generating capacity
- A downward sloping (rather than a vertical) demand curve, called the VRR curve
- Administrative and empirical determinations of the net cost of new entry (“Net CONE”)
- Performance monitoring during the delivery year and peak periods
- Consistency with self-supply and bilateral procurement of capacity
- An opt-out mechanism under the Fixed Resource Requirement (FRR) alternative

Explicit market monitoring and mitigation rules, including a must-offer requirement for existing generating resources and IMM review and mitigation of new entrant offers

- **Self-supply and Bilateral Procurement of Capacity—**The RPM market design allows LSEs to self-supply resources to meet their capacity obligations either by designating resources they own or purchase bilaterally. Such capacity must be offered into base auctions. The main purpose of the base auctions is to purchase capacity needs not met by self-supplied resources.
- **Fixed Resource Requirement—**The FRR alternative allows LSEs to opt-out of RPM and, instead, meet a fixed capacity obligation. LSEs that choose the FRR option are subject to certain qualification requirements and face restrictions on the amount of capacity they may sell in RPM auctions. The area of Michigan’s transmission system operated by PJM and owned by Indiana Michigan Power Company (I&M), an operating subsidiary of American Electric Power (AEP), participates in the PJM resource Adequacy construct under the FRR opt-out provision, choosing to not participate in the RPM (PJM n.d.).

Appendix J

Five-year Electric Reliability Supply Plans

	PY 2015-2016	PY 2016-2017	PY 2017-2018	PY 2018-2019	PY 2019-2020
Consumers Energy (Customers 1,790,148, 37.68%)					
Total Planning Reserve Margin (expected reserves), UCAP MW	8,094	8,066	8,039	8,043	8,036
Total Planning Resources, MW	8,103	8,087	8,040	8,063	8,079
Surplus/(Shortfall), MW	9	21	1	20	43
DTE Energy (Customers 2,134,569, 44.93%)					
Total Planning Reserve Margin (expected reserves), UCAP MW	10,979	11,024	11,085	11,103	11,095
Total Planning Resources, MW	10,858	11,105	11,104	11,173	11,198
Surplus/(Shortfall), MW	(121)	81	19	70	103
Indiana Michigan Power Company (Customers 127,908, 2.69%)					
Total Planning Reserve Margin (expected reserves), UCAP MW	4,755	4658	4,696	4,616	4,636
Total Planning Resources, MW	4,733	4602	4,644	4,676	4,680
Surplus/(Shortfall), MW	(22)	(56)	(52)	60	44
Upper Peninsula Power Company (Customers 52,035, 1.10%)					
Total Planning Reserve Margin (expected reserves), UCAP MW	158	158	158	158	158
Total Planning Resources, MW	166	162	110	110	110
Surplus/(Shortfall), MW	8	4	(48)	(48)	(48)
Wolverine Power Supply Cooperative* (Cooperative Customers 249,575, 5.25%)					
Total Planning Reserve Margin (expected reserves), UCAP MW	886	890	894	896	899
Total Planning Resources, MW	1,056	1,374	1,105	1,055	1,055
Surplus/(Shortfall), MW	170	484	211	159	156

* Includes Cherryland, Great Lakes, HomeWorks, Midwest Energy Cooperative (Midwest), Presque Isle, Wolverine Power Marketing Cooperative, Inc. (WPMC) and Spartan Renewable Energy, Inc. (Spartan))
SOURCE: MPSC. December 4, 2014. Case No. U-17751. Available at: http://efile.mpsc.state.mi.us/efile/docs/17751/0001.pdf (accessed 1/21/15)

Appendix K

MPSC Electric Utility Cost Recovery Proceedings

Power Supply Cost Recovery (PSCR) Plan

- **Purpose:** Minimize and ensure timely recovery of fuel and purchased power costs
- **Scope:**
  - Review reasonableness and prudence of annual utility plan with respect to fuel and other eligible expenses
  - Provide up-front approval of annual plan and associated PSCR charges assessed to customers (subject to reconciliation)
  - Review five-year forecast of sales, supply sources, and power supply costs “in light of existing sources of generation” and generation “under construction”
- **Frequency:** Annual
- **Timing:**
  - Plan case must be filed not less than 3 months prior to the 12-month PSCR plan period
  - No statutory deadline for MPSC to issue final order
- **Statutory Reference:** PA 304 of 1982 (MCL 460.6j)

PSCR Reconciliation

- **Purpose:** Reconcile PSCR revenues with actual expenses
- **Scope:**
  - Reconcile PSCR revenues with actual expenses and allow for refunds or surcharges for over- or under-collections
  - Consider any issue regarding reasonableness and prudence of expenses for which customers were charged if the issue was not considered adequately in power supply and cost review
  - Disallow certain costs specified in the Act, including any power purchase agreements of 6 months or more not previously approved by the Commission
- **Frequency:** Annual
- **Timing:** Reconciliation proceeding must be commenced not later than 3 months after the end of the 12-month PSCR plan period
- **Statutory Reference:** PA 304 of 1982 (MCL 460.6j)

Base Rate Case

- **Purpose:** Review utility requests to increase base rates
- **Scope:**
  - Review utility applications that allege a revenue deficiency and request an increase in the schedule of rates or charges based on the utility’s total cost of providing service
  - Determine whether an increase in utility revenues will be authorized
  - Determine what groups of customers (e.g., residential, commercial, industrial) will be affected
  - Determine new rates designed to collect appropriate revenues from customers
- **Frequency:**
  - Upon utility application for increased rates, but no more than once per year

- Commission may issue show-cause order at any time (typically done if utility earnings are in excess of authorized amounts)

❖ **Timing:**
- Self-implementation of rates allowed if final order is not issued within 6 months of application
- Final order required to be issued within 12 months

❖ **Statutory Reference:** PA 286 of 2008 (MCL 460.6a)

Cost Re-Allocation

❖ **Purpose:** Examine cost allocation methods and rate design methods used to set rates

❖ **Scope:**
- Review proposals to modify the existing cost allocation methods and rate design methods that have been used to set existing rates. Utility filings must:
  - Be consistent with provisions which authorize the Commission to modify the 50-25-25 method of allocating production-related and transmission costs to better ensure rates are equal to the cost of service
  - Explore different methods for allocation of production, transmission, distribution, and customer-related costs and overall rate design, based on cost of service, that support affordable and competitive electric rates for all customer classes

❖ **Frequency:** One-time proceedings – mandatory for Consumers, DTE, I&M; optional for other IOUs/regulated co-ops

❖ **Timing:**
- Final order for DTE/Consumers required to be issued within 9 months and be able to be implemented prior to December 1, 2015
- No statutory deadline for other utility proceedings

❖ **Statutory Reference:** PA 169 of 2014 (MCL 460.11)

Certificate of Necessity (CON)

❖ **Purpose:** Consideration of pre-approval of generation resource construction/expansion/ purchase/contract costs in excess of $500 million

❖ Scope:
- Review request for a certificate of necessity for construction, expansion, acquisition, or contractual purchases of generation resources in excess of $500 million
  - CON cannot be issued for projects related to renewable energy systems or making environmental upgrades
- Determine need for power from proposed generation resources conforming with an approved integrated resource plan
- Determine reasonableness of the estimated cost of proposed generation resources
- Determine whether the proposed generation resources are most reasonable and prudent way of meeting the power need
- Determine whether the proposed generation resources are in compliance with applicable environmental standards and that to the extent practicable, any construction will take place using a workforce comprised of Michigan residents

❖ **Frequency:** Upon utility application

❖ **Timing:** A final order must be issued within 270 days of a utility's application

❖ **Statutory Reference:** PA 286 of 2008 (MCL 460.6s).

Energy Optimization (EO) Plan

- **Purpose:** Consideration of utility's plan to achieve applicable energy optimization standard
- **Scope:**
  - Determination of whether an EO plan meets the Utility System Resource Cost Test (i.e., is cost-effective) and whether the plan is reasonable and prudent
  - Consideration of whether the plan would reduce the future cost of service for a provider's customers
  - Consideration of the following:
    - The specific changes in customers' consumption patterns that the proposed EO plan is attempting to influence
    - The cost and benefit analysis and other justification for specific programs and measures included in a proposed EO plan
    - Whether the proposed EO plan is consistent with any long-range resource plan filed by the provider with the commission
    - Whether the proposed EO plan will result in any unreasonable prejudice or disadvantage to any class of customers
    - The extent to which the EO plan provides programs that are available, affordable, and useful to all customers
- **Frequency:**
  - Initial plans required to be filed within specified timeframes after enactment of PA 295
  - Commission review is required every two years after the initial plan approval (MPSC March 2013)
  - Utilities may file a proposed plan amendment at any time
- **Timing:** Initial and amended plans must have an MPSC order within 90 days
- **Statutory Reference:** PA 295 of 2008 (MCL 460.1073)

EO Reconciliation

- **Purpose:** Reconcile energy optimization revenues with actual and projected expenses to comply with standard
- **Scope:**
  - Reconcile energy optimization revenues with actual and projected expenses to comply with standard
  - If necessary, modify revenue recovery mechanism (EO surcharge) to ensure recovery of costs of compliance
  - Determine providers' compliance with EO standard
- **Frequency:** Annually
- **Timing:** No statutory deadline for MPSC to issue final order
- **Statutory Reference:** PA 295 of 2008 (MCL 460.1073)

Renewable Energy (RE) Plan

- **Purpose:** Consideration of a utility's plan to achieve 10% by 2015 renewable energy standard and maintain the 2015 quantity of RECs through the end of the plan period in 2029.
- **Scope:**
  - Review utility's plan to meet renewable energy standard [35]

[35] Non-rate-regulated providers have modified requirements for plan content and case processing procedure (MCL 460.1023 and MCL 460.1025).

- Determine expected incremental cost of compliance to meet the renewable energy standard over 20-year plan period, and establish RE surcharges when applicable
- Approve competitive bidding processes for Consumers and DTE
- Determine whether RE plan is reasonable and prudent
- Determine whether life cycle costs of RE plan plus life-cycle net savings attributable to energy optimization plans do not exceed the expected life-cycle cost of electricity generated by a new conventional coal-fired facility

❖ **Frequency:**
  - Initial plans required to be filed within specified timeframes after enactment of PA 295
  - Commission review is required every 2 years after the initial plan approval during the 20-year plan period
  - Utilities may file a proposed plan amendment at any time

❖ **Timing:** MPSC issues order within 90 days for the initial plan and any amendments. No statutory deadline for MPSC to issue final order for biennial review filings

❖ **Statutory Reference:** PA 295 of 2008 (MCL 460.1021)

RE Reconciliation

❖ **Purpose:** Reconcile renewable energy revenues with actual expenses to comply with standard

❖ **Scope:**
  - Reconcile renewable energy revenues with actual and projected expenses to comply with standard
  - If necessary, modify revenue recovery mechanism (RE surcharge) to ensure recovery of incremental cost of compliance
  - Determine providers' compliance with RE standard
  - Establish "transfer price" for renewable energy and renewable energy capacity to be recovered through the PSCR mechanism
  - If necessary, adjust the minimum balance of accumulated reserve funds

❖ **Frequency:** Annually

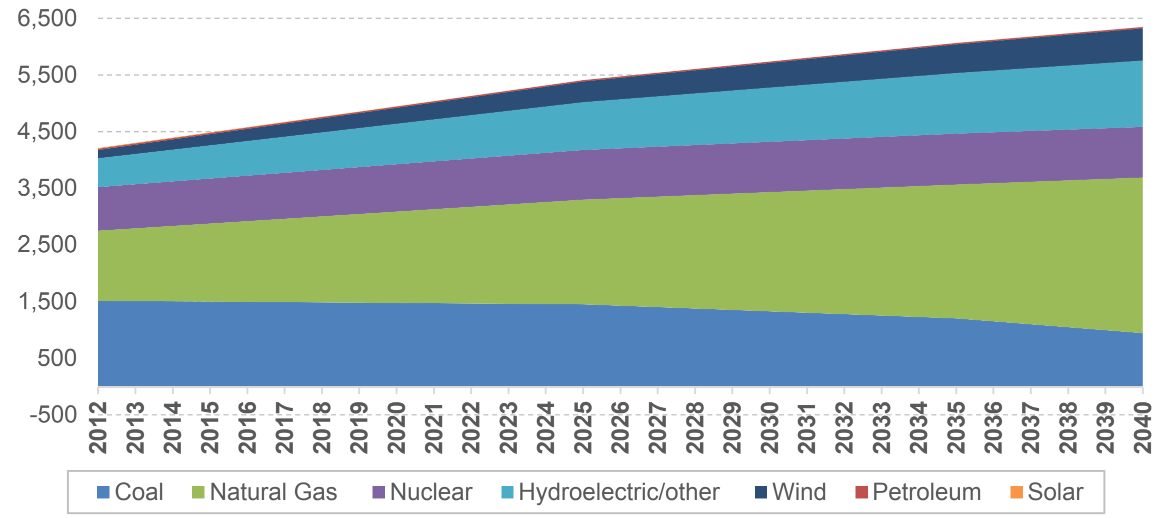
❖ **Timing:** No statutory deadline for MPSC to issue final order

❖ **Statutory Reference:** PA 295 of 2008 (MCL 460.1049)

Appendix L

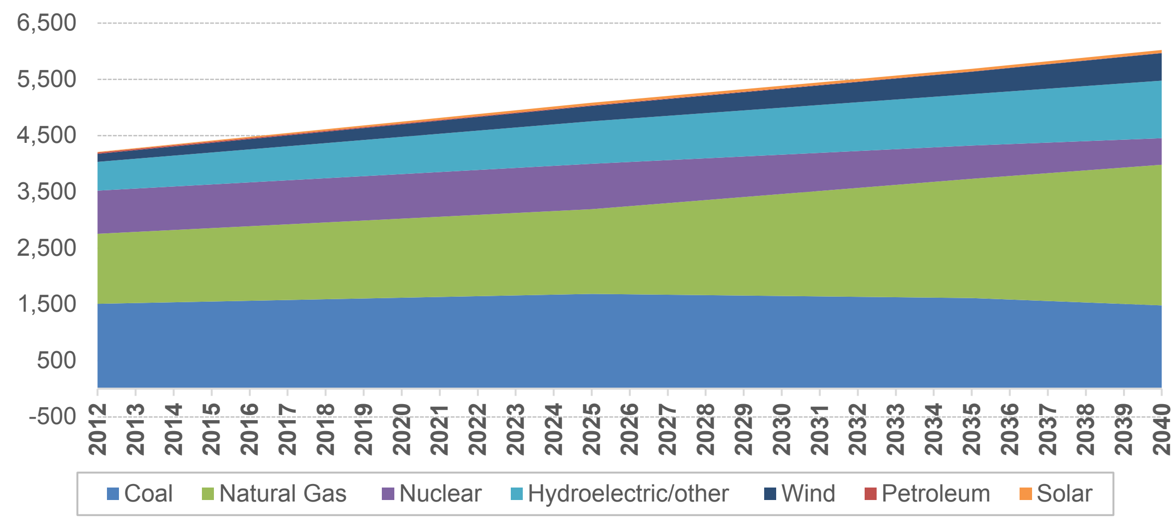
Various Projections for Electric Generation Growth

IHS Global Insight Projection: Fuel Mix for Electric Generation, 2012–2040

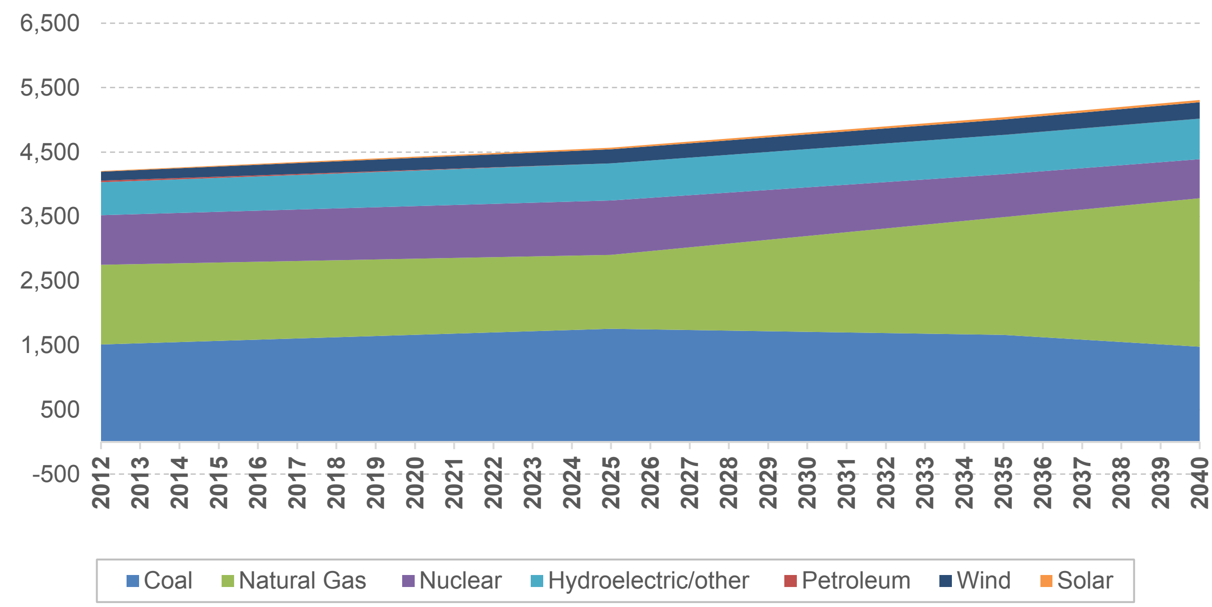


SOURCE: U.S. EIA. May 7, 2014. *Annual Energy Outlook 2014*. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf. (accessed 3/3/15)

ICF Projection: Fuel Mix for Electric Generation, 2012–2040



EVA Projection: Fuel Mix for Electric Generation, 2012–2040



Appendix M

Michigan Renewable Resource Assessment

Vermont Energy Investment Corporation. April 8, 2015. *Michigan Renewable Resource Assessment Final Report*. Prepared for: Michigan Public Service Commission. Available at: http://www.michigan.gov/documents/mpsc/VEIC_Renewables_Assessment_487864_7.pdf?20150427145352 (accessed 5/5/15)