Chapter 8 Need For Power

This chapter demonstrates the need for power and related benefits to be generated by the proposed facility. The proposed facility is located within Monroe County in the State of Michigan.

The demonstration of the need for power is organized into the following sections:

Section 8.1 provides a description of the power system, an overview of the pertinent service area, and a discussion of regional relationships. Sufficient detail is provided to gain an understanding of the configuration in the State of Michigan and relationships with other entities.

Section 8.2 provides a description of the analysis performed to determine current and forecasted energy needs in the State of Michigan. The energy forecasts represent the aggregate product of individual forecasts made by investor-owned, municipal, and cooperative utilities. In addition to assessing a base case growth forecast, cases considering low growth and high growth have also been performed. Section 8.2 also discusses factors that can affect growth of demand; i.e., forecasting uncertainties, energy efficiency, and conservation.

Section 8.3 provides a description of the analysis performed to determine energy supply resources. Energy supply resources consist of the existing generating capability plus forecasted generating capability plus (or subtracting) transmission capabilities in (or out) of the service area and subtracting forecasted unit retirements.

Section 8.4 provides a description of the assessment of the need for power. The assessment of the need for power balances the current and forecasted demand against the current and forecasted supply, while demonstrating that an adequate reserve margin is maintained. The assessment includes several different scenarios and sensitivities to provide a comprehensive and rigorous evaluation.

As clearly shown in this chapter, the State of Michigan has a need for new baseload capacity and this need is projected to increase. Michigan's current baseload generating units are an average of more than 48 years old. As discussed in Section 8.3, modeling for the analyses used in this assessment assumes that older, less efficient units, totaling 3755 MW of capacity, will be retired by 2025. The last new baseload plant in the State of Michigan began commercial operation more than 18 years ago. In recent years, new electric generation in Michigan has been limited to natural gas-fired facilities. Natural gas-fired units represented about 10 percent of the State's generating capacity in 1992, but now represent approximately 29 percent of that generating capacity. These units were built by independent power producers (IPPs). Many IPPs have subsequently gone through bankruptcy as the rise in natural gas prices over the past several years made even the most efficient units uneconomic to run for more than a few hours each year. Market prices driven by natural gas costs expose Michigan to volatile electricity prices. Establishing new baseload supply will help to provide price stability.

Detroit Edison operates within the ITC*Transmission* service area. ITC*Transmission* operates within the Midwest Independent Service Operator (Midwest ISO) regional reliability area as discussed in Section 8.1. The goal of the Midwest ISO is to provide reliable electrical power. Detroit Edison provides most of the electricity used in southeastern Michigan. Detroit Edison's mission is to provide reliable and affordable electrical power.

The proposed Fermi 3 strategically enables Detroit Edison to meet its mission. Being a nuclear unit, the proposed Fermi 3 is strategic in that it helps reduce reliance on fossil fuels. Currently, the State of Michigan relies heavily on electrical generation from coal and natural gas. A new nuclear unit will help to diversify the energy supply for the State of Michigan.

In addition, using nuclear power for electrical generation reduces air emissions (e.g., nitrogen oxides, sulfur dioxide, and carbon dioxide) that result from fossil fuel-fired electrical generation. Apart from water vapor, modern nuclear reactors produce virtually no air emissions. Nuclear power generation, therefore, leads to significant local, national, and global air quality benefits.

Pursuant to Executive Directive No. 2006-02 (Reference 8.0-3), the Michigan Public Service Commission (MPSC) prepared and issued Michigan's 21st Century Electric Energy Plan (Reference 8.0-1). The plan is comprehensive in its scope and inclusive in its development. It was developed with input from more than 150 organizations. Interested persons were divided into four Workgroups – the Capacity Need Forum Update Workgroup, the Energy Efficiency Workgroup, the Renewable Energy Workgroup, and the Alternative Technologies Workgroup. These four Workgroups were further subdivided into Teams. In all, over 35 Workgroup/Team meetings and five large group meetings were held, and approximately 4000 pages of documents were filed with, or prepared by, the MPSC Staff. The website, cited as part of the 21st Century Plan was used to post relevant information. Workgroup reports, membership lists, presentation handouts, participant's comments, and other draft documents can be found at this location. The final Workgroup reports can be found in Appendix Volume II of the plan. A complete list of participants can be found in Appendix Volume I, Section 6. Several significant conclusions include:

- Michigan's peak electric demand is forecast to grow at approximately 1.2 percent per year for the next 20 years. At this rate, and given the long lead-time necessary for major plant additions, additional baseload generation is projected to be necessary as soon as practicable but no later than 2015.
- Extensive modeling of Michigan's electric utility industry demonstrates the need for additional electric generating resources in order to preserve electric reliability and provide affordable energy over the next 20 years. This modeling outcome is confirmed even in the presence of increased use of energy efficiency and renewable resources.
- This same modeling outcome is also confirmed in the presence of expanded transmission and access to external markets, and reflects the diminishing availability of the Midwest ISO regions baseload generation capacity.
- Recent estimates show that the cost of natural gas (or equivalent fuel) is often setting the wholesale on-peak prices within the Midwest ISO region. If regulated baseload capacity is not increased in the near future, natural gas prices will drive up wholesale costs and market prices for an increasing number of hours each year.

NUREG-1555 (Reference 8.0-2), Section 8.1, “Description of Power System,” Subsection I, under the heading Data and Information Needs states:

> Affected States and/or regions may prepare a need-for-power evaluation as part of a State or regional energy planning exercise. Similarly, State or regional agencies may require the applicant to document a need for power or plan for future plant construction. The applicant may choose to rely on those documents rather than prepare a description of the power system of its own. If so, NRC staff should review these documents to determine if they are (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. Of particular concern are third-party plans or reports restricted to boundaries smaller than relevant service and market areas. Another concern is plans and studies that do not extend far enough into the future to provide an adequate basis for comparison. If NRC staff concludes these other documents are acceptable, no additional independent review by NRC staff may be needed and that analysis can be the basis for ESRPs 8.2 through 8.4.

The Michigan 21st Century Electric Energy Plan satisfies the NRC’s evaluation criteria of being (1) systematic; (2) comprehensive; (3) subject to confirmation and; (4) and responsive to forecast uncertainty. The basis for this conclusion is discussed in Subsection 8.1.5, below.

8.0.1 References

8.0-1 Lark, J. Peter, Chairman, Michigan Public Service Commission, “Michigan’s 21st Century Electric Energy Plan,” Submitted to Honorable Jennifer M. Granholm, Governor of Michigan, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm, accessed 18 January 2008.

8.0-2 Nuclear Regulatory Commission, “Standard Review Plans for Environmental Reviews of Nuclear Power Plants,” NUREG-1555, Revision 1, July 2007.

8.0-3 Granholm, J.M., Governor, State of Michigan, “21st Century Energy Plan,” Executive Directive No. 2006-02, http://www.michigan.gov/gov/0,1607,7-168-36898-140415--,00.html, accessed 9 July 2008.

8.1 Description of Power System

This section describes and assesses the regional power system in which the proposed facility will operate. This section includes a brief description of the proposed project, a description of the power system, service area, and regional relationships.

The State of Michigan's 21st Century Electric Energy Plan (Reference 8.1-1) serves as the primary input to the overall Need for Power assessment presented in this chapter. Subsection 8.1.5, below, describes how the plan satisfies the NRC evaluation criteria of being (1) systematic; (2) comprehensive; (3) subject to confirmation; and (4) responsive to forecast uncertainty.

8.1.1 **Project Description**

The proposed location of the new facility is near Monroe, Michigan, on the existing Fermi site. Fermi 2, a Boiling Water Reactor of approximately 1100 MWe, currently operates on the site. Fermi 2 is operated by the Detroit Edison Company and is linked to load centers by a system of transmission lines in the ITC*Transmission* system. ITC*Transmission* owns and operates the electrical switchyard at Fermi 2 and the adjoining electrical transmission system.

The proposed unit is referred to as Enrico Fermi Unit 3 (Fermi 3). Fermi 3 is proposed as a single unit ESBWR design. Fermi 3 is designed to operate at approximately 1600 MWe (estimated gross electrical power output). Ownership of Fermi 3 is described in Section 1.1. Based on current milestone scheduling, the anticipated date for commercial operation is 2020.

8.1.2 **Power System**

Detroit Edison generates electricity to 2.2 million customers in southeastern Michigan. With an 11,080 MWe system capacity, the company uses coal, nuclear, natural gas, and hydroelectric pumped storage to generate its electrical output. Founded in 1903, Detroit Edison is the largest electric utility in Michigan and one of the largest in the nation (Reference 8.1-2).

Figure 8.1-1 shows the electric utility service areas for the State of Michigan (Reference 8.1-3). Figure 8.1-1 shows the areas serviced by the different utilities operating within the State of Michigan. As shown on Figure 8.1-1, Detroit Edison and Consumers Energy supply the majority of the electric power service area in the Lower Peninsula of Michigan.

Figure 8.1-2 shows the major power generation facilities in the State of Michigan and the power grid connections in and out of the State (Reference 8.1-4). The major generation facilities are coal-powered, gas/oil powered, nuclear powered, and hydroelectric. Coal and nuclear power are Michigan's chief energy sources. Reliability and price stability are protected by a mix of fuel sources. Figure 8.1-3 provides a different perspective of the location of electric power plants and transmission line configuration in the State (Reference 8.1-5). Power plants are shown in lieu of operating units, recognizing that more than one unit may be operating at each power plant location. Transmission lines are shown based on voltage class, including a proposed 765 kV line, which is discussed later in Subsection 8.3.2.

As discussed above, electric power produced at Fermi 2 is linked to load centers by a system of transmission lines in the ITC*Transmission* organization. ITC*Transmission* owns and operates the electrical switchyard at Fermi 2 and the adjoining electrical transmission system. In November 1999, ITC*Transmission* was created as an independently functioning business unit within Detroit Edison. This was the first step in the formation of a truly independent, stand-alone transmission company. In May 2000, ITC*Transmission*, Detroit Edison and DTE Energy filed a joint application with the Federal Energy Regulatory Commission (FERC), seeking permission to transfer all jurisdictional transmission assets from Detroit Edison to ITC*Transmission*. This permission was granted in June 2000. On June 1, 2001, ITC*Transmission* began operations as a wholly owned subsidiary of DTE Energy. In December of that year, ITC*Transmission* joined the Midwest Independent System Operator (Midwest ISO), a FERC-approved regional transmission organization. It was the first company to join Midwest ISO under Appendix I of the Midwest ISO agreement, which allowed an independent transmission company certain freedoms to continue operation as a for-profit stand-alone business. On February 28, 2003, ITC*Transmission* became a stand-alone transmission company following the sale of transmission assets from DTE Energy. On April 8, 2004, ITC*Transmission* became the country's first fully independent transmission company after they completed the transition by assuming construction and maintenance activities from DTE Energy. (Reference 8.1-6)

The ITC*Transmission* service area is shown on Figure 8.1-4 (Reference 8.1-7). The ITC*Transmission* service territory covers approximately 19,600 square kilometers (7600 square miles) throughout 13 counties in Michigan, including the metropolitan areas of Detroit and Ann Arbor. ITC*Transmission* facilities include approximately 2700 circuit miles of overhead and underground transmission lines, 17,000 towers and poles, and 155 stations and substations. (Reference 8.1-8)

The parent company for ITC*Transmission* also owns the Michigan Electric Transmission Company, LLC (METC). Figure 8.1-5 shows the METC service area (Reference 8.1-9). Together, ITC*Transmission* and METC have responsibility over the majority of the transmission system in Michigan's Lower Peninsula and work to improve the transmission infrastructure in order to accomplish the goal; which is to improve electric reliability.

8.1.3 **Service Area Overview**

ITC*Transmission* operates within the Midwest ISO regional reliability area, and is a member of Midwest ISO. Figure 8.1-6 shows the Midwest ISO regional reliability area (Reference 8.1-10). The Midwest ISO is an essential link in the safe, cost-effective delivery of electric power across much of North America. The Midwest ISO is committed to reliability, the nondiscriminatory operation of the bulk power transmission system, and to working with all stakeholders to create cost-effective and innovative solutions for the changing industry. (Reference 8.1-11)

The Midwest ISO is an independent, nonprofit organization that supports the constant availability of electricity in 15 States and the Canadian province of Manitoba. This responsibility is carried out by ensuring the reliable operations of nearly 94,000 miles of interconnected high voltage power lines that support the transmission of more than 100,000 MW of energy in the Midwest, by administering one of the world's largest energy markets, and by looking ahead to identify improvements to the wholesale bulk electric infrastructure that will best meet the growing demand for power in an efficient and effective manner (Reference 8.1-13). A system agreement governs the interaction of the various transmission facility owners of the Midwest ISO as one power pool. The current version of the tariff was filed with the Federal Energy Regulatory Commission in 2007 for approval of various revisions to the subsequent tariff.

Table 8.1-1 through Table 8.1-4 provide the following information for Detroit Edison Company and for the State of Michigan (Reference 8.1-12).

- Table 8.1-1 provides sales information by rate class (i.e., residential, commercial, and industrial).
- Table 8.1-2 provides numbers of customers for each rate class (i.e., residential, commercial, and industrial).
- Table 8.1-3 provides average sales per customer which is determined from the information in Table 8.1-1 and Table 8.1-2. As shown in Table 8.1-3, the electrical power use per customer in commercial and industrial sectors serviced by Detroit Edison is greater than that for the State of Michigan overall.
- Table 8.1-4 provides percentage of total electrical power usage by rate class (residential, commercial, and industrial).

8.1.4 **Regional Relationships**

The Midwest ISO works together with PJM Interconnection LLC (PJM) to develop complementing system operations and one robust, non-preferential wholesale electricity market to meet the needs of all customers and stakeholders in 23 States, the District of Columbia, and the Canadian province of Manitoba. The market is being developed through an open stakeholder process and is being designed to serve residents regardless of whether they reside in States with bundled or unbundled retail rates. The Midwest ISO Regional Reliability Area and the PJM Service Area are shown on Figure 8.1-6. (Reference 8.1-10)

The North American Electric Reliability Corporation (NERC) works with eight regional entities to improve the reliability of the bulk power system. The members of the regional entities come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; State, municipal, and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The areas of the Lower Peninsula of Michigan serviced by the Midwest ISO and the PJM Interconnection are located within the Reliability*First* Corporation NERC regional entity geographic area.

Reliability*First* is a not-for-profit company incorporated in the State of Delaware, which began operations on January 1, 2006. Figure 8.1-7 provides a map showing the boundaries of the Reliability*First* region with the NERC (Reference 8.1-14). Reliability*First*'s mission is to preserve and enhance electric service reliability and security for the interconnected electric systems within the Reliability*First* geographic region. On July 20, 2006, the NERC was certified as the Electric Reliability Organization (ERO) in the United States, pursuant to Section 215 of the Federal Power Act of 2005. Included in this certification was a provision for the ERO to delegate authority for the purpose of proposing and enforcing reliability standards by entering into delegation agreements with regional entities. Reliability*First* is one of the eight approved Regional Entities in North America, under the NERC. Reliability*First*'s primary responsibilities include developing reliability standards and monitoring compliance to those reliability standards for all owners, operators and users of the bulk electric system, and providing seasonal and long term assessments of bulk electric system reliability within the Region.

8.1.5 **Michigan's 21st Century Electric Energy Plan**

As described in the Introduction above, the Michigan 21st Century Electric Energy Plan satisfies the NRC's evaluation criteria of being (1) systematic; (2) comprehensive; (3) subject to confirmation; and (4) responsive to forecast uncertainty. The Michigan 21st Century Electric Energy Plan extends beyond Detroit Edison's direct service area and addresses the needs for the State. The planning period for the Michigan 21st Century Electric Energy Plan extends through 2025, or well beyond the planned date of commercial operation for the proposed project. The basis for the conclusion that the plan satisfies the NRC evaluation criteria is discussed below.

8.1.5.1 **Systematic Process**

The Michigan 21st Century Electric Energy Plan was developed using a systematic process for load forecasting. The forecast was developed using accepted techniques and employs a wide range of explanatory variables. As discussed above, the plan was developed using several different teams working together to complete the effort. Load forecasting was performed by the Capacity Need Forum (CNF) Update Workgroup. The CNF Update Workgroup was charged with reviewing and providing updates to five principal data and analysis sections of the CNF study from 2005 (Reference 8.1-16). These five tasks are summarized below.

- First the CNF Update Workgroup reviewed and updated information on central station generation options. This task included confirming the inventory of generating plants currently operational in Michigan and reviewing investment and operating costs, performance, and emissions profiles of central station generation technologies, and assessing planning reserve requirements.
- Second, the CNF Update Workgroup reviewed the transmission analysis performed for Reference 8.1-16, confirming the simultaneous, on-peak transmission capability, and determining the amount of capability available for reliability support for the Lower Peninsula of Michigan.
- Third, the CNF Update Workgroup was responsible for electric reliability assessments for regions within Michigan.
- Fourth, the CNF Update Workgroup provided an updated twenty-year electric sales and peak demand forecast for Michigan. As in Reference 8.1-16, the long term forecast was provided for each of the three geographical regions within Michigan.

- Fifth, the CNF Update Workgroup managed the expansion modeling, provided fuel and emission cost forecasts, and developed model scenarios and sensitivities.

The CNF Update Workgroup followed the same process used in Reference 8.1-16 and relied on data, analysis, and narrative from that effort where appropriate. The CNF Report and associated Workgroup Reports, including description of methodologies utilized, are provided in Reference 8.1-16.

The load projections rely primarily on forecast data provided by members of the Workgroups including: Consumers Energy, Detroit Edison, Wolverine Power Cooperative, Michigan municipal utilities, WE Energies, and WPS Energy. Various methods are used by each of these participants to forecast their loads. The annual forecast is prepared for each of the three geographical regions in Michigan: Southeast Michigan, comprising the area served by ITC*Transmission*, the balance of the Lower Peninsula, comprising the area served by the METC and the Upper Peninsula, comprising the American Transmission Company (ATC) Zone 2 region.

8.1.5.2 **Comprehensive Process**

The inputs to the Michigan 21st Century Electric Energy Plan considered a comprehensive set of model parameters.

First, the varied list of participants in the project helped to ensure the comprehensive nature of the process. For example, participants in CNF Update Workgroup included representatives from the Michigan Public Service Commission, Outside Consultants, Renewable Energy Association, Utilities, Unions, Universities, Michigan Department of Environmental Quality, Community Action, Industry, etc. The breadth and depth of the workgroup members brings several interests to bear on the process, helping to assure a comprehensive process.

As discussed above, the regional forecasts represent composite projections made by individual participants. Southeast Michigan's forecast is based almost exclusively on Detroit Edison's projections. Detroit Edison uses a comprehensive set of economic parameters as part of their forecasting methodology including automobile and truck production, Detroit steel production, Detroit and Ann Arbor non-industrial employment, Detroit index of coincident indicators, industrial production index, and housing permits. The forecast for the balance of the Lower Peninsula includes Consumers Energy, Wolverine Power Cooperative, municipal utilities, and several other utilities, with Consumers Energy's forecast contributing the majority of the forecasted load. Consumers Energy uses a comprehensive set of economic parameters as part of their forecasting methodology, including U.S. industrial production eight sector average, Michigan industrial production six sector average, composite Michigan transportation index, and Michigan housing starts. Wolverine Power Cooperative's forecast is developed at the member-distribution cooperative level and rolled up to crease a single Wolverine system forecast. Wolverine's various forecasts are based on residential sales, seasonal sales, commercial forecasts, industrial forecasts, etc. Municipal utility forecasts in the Lower Peninsula are based on past individual trends of each individual municipality taking into account specific customer information. The Upper Peninsula's forecast reflects the aggregation of several investor-owned utilities and municipal utilities. Three of the five investor-owned utilities in the Upper Peninsula are multi-State owned utilities and generally forecast loads on a system-wide basis. These system-wide load forecasts utilize econometric forecasting methods. The load forecasts for the remaining two Michigan-only investor-owned utilities and two municipal electric utilities reflect the use of general historical load growth trends.

8.1.5.3 Subject to Confirmation

The Michigan 21st Century Electric Energy Plan forecast methods and results are subject to confirmation by multiple parties. The goal of the Michigan Public Service Commission (MPSC) was to ensure that the process used to develop the plan was transparent and all-inclusive. The MPSC actively sought input and welcomed participation from all individual and organizations interested in Michigan's electric industry and energy future.

Representatives from customer groups, business groups, jurisdictional and non-jurisdictional utilities, independent transmission companies, environmental groups, energy efficiency advocates, independent power developers, and alternative and renewable energy providers were active in the process. The diversity of the participants ensured that all interests were considered in development of the plan.

As the workgroups develop the information and recommendations that eventually make up the overall plan, the development is scrutinized first on the individual team level, then within the overall work group and through interactions between the four workgroups. Prior to completion of the plan and submittal to the Governor of the State of Michigan, the overall plan was reviewed in detail by the participating individuals and organizations.

In addition, as part of the review, strawman proposals for energy policy were provided to several different organizations for review and comment. These organizations included pubic interest groups, electric utilities, trade association, etc. The review comments can be found at Reference 8.1-17. This review provided broad cross-sectional review of the policy proposals as part of development of the overall assessment.

8.1.5.4 Responsive to Forecast Uncertainty

The forecasting methodology included consideration of uncertainties due to (1) weather; (2) accurately capturing business cycles in lieu of simply trending projections; (3) future economic conditions (the motor vehicle industry remains a major factor affecting electricity requirements in Michigan and remains a major uncertainty); and (4) the consumer market for electric appliances.

In addition to the base case, the load forecasts included high growth and low growth cases to capture these uncertainties. The modeling for the assessment of the need for power in the 21st Century Electric Energy Plan included several different scenarios. Each scenario model included several sensitivities. The combination of scenarios and sensitivities provided a methodology to rigorously address potential uncertainties in the forecast.

8.1.5.5 Additional Considerations

Additional considerations for the relevance of the Michigan 21st Century Electric Energy Plan are assuring that the plan addresses the relevant service and market areas and that the planning period extends sufficiently into the future to provide an adequate basis for comparison.

The boundaries evaluated for the Michigan 21st Century Electric Energy Plan extends beyond Detroit Edison's direct service area. Included in the forecast are all electric load-serving entities in the State of Michigan. As discussed in Section 8.2, the demand forecasts are performed for Southeast Michigan, the Balance of the Lower Peninsula, and the Upper Peninsula. Southeast Michigan's forecast is based almost exclusively on Detroit Edison's projections, where the forecasts for the Balance of the Lower Peninsula and the Upper Peninsula are based on forecasts from other entities. In addition to the regulated investor-owned utilities, this includes the regulated electric cooperatives and non-regulated municipal utilities. The forecast includes the total service territory sales for Consumers Energy and Detroit Edison, consisting of both bundled and competitive choice customers.

Commercial operation for the proposed project is 2020. The planning period for the Michigan 21st Century Electric Energy Plan extends through 2025. Therefore, the period considered for the Michigan 21st Century Electric Energy Plan extends sufficiently into the future to provide an adequate basis for comparison.

8.1.6 References

8.1-1 Michigan Public Service Commission, "Michigan's 21st Century Electric Energy Plan," submitted to Honorable Jennifer M. Granholm, Governor of Michigan, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm, accessed 18 January 2008.

8.1-2 DTE Energy, "MichCon/Detroit Edison Service Areas," http://www.dteenergy.com/businesses/utility.html, accessed 18 January 2008.

8.1-3 Michigan Public Service Commission, "Electric Utility Service Areas," http://www.dleg.state.mi.us/mpsc/electric/map.htm, accessed 18 January 2008.

8.1-4 Energy Information Administration, "State and U.S. Historic Data, State Energy Profiles, Michigan," http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=MI, accessed 22 August 2008.

8.1-5 Michigan Transmission Map, developed from information accessed through web-site http://www.globalenergy.com/products-vs-overview.asp, accessed 14 January 2008.

8.1-6 ITC*Transmission*, "History and General Information," http://www.itctransco.com/app.php?sec=&id=3, accessed 18 January 2008.

8.1-7 ITC*Transmission*, "Service Area Map," http://www.itctransco.com/app.php?sec=1&id=2, accessed 18 January 2008.

8.1-8 ITC*Transmission*, "General Information," http://www.itctransco.com/app.php?sec=1&id=2, accessed 18 January 2008.

8.1-9 Michigan Electric Transmission Company, "METC Service Area Map," http://www.metcllc.com/app.php?sec=1&id=1, accessed 18 January 2008.

8.1-10 Midwest ISO - PJM Interconnection Joint and Common Market Web site, http://www.miso-pjm.com/, accessed 18 January 2008.

8.1-11 Midwest ISO, “Welcome to Midwest ISO,” http://www.midwestiso.org/page/MisoPortalHome, accessed 18 January 2008.

8.1-12 Energy Information Administration, “EIA-861 Database,” http://www.eia.doe.gov/cneaf/electricity/page/eia861.html, accessed 24 January 2008.

8.1-13 Midwest ISO, “About Us,” http://www.midwestiso.org/page/About%20Us, accessed 18 January 2008.

8.1-14 Reliability First, “Regional Map,” http://www.rfirst.org/MiscForms/AboutUs/Territory.aspx, accessed 18 January 2008.

8.1-15 Nuclear Regulatory Commission (NRC), “Standard Review Plans for Environmental Reviews of Nuclear Power Plants,” NUREG-1555, Revision 1, July 2007.

8.1-16 Stojic, G., Director Operations & Wholesale Markets Division, to Michigan Public Service Commission, Chairman J. Peter Lark, Commissioner Laura Chappelle, and Commissioner Monica Martinez, “Final Staff Report of the Capacity Need Forum,” (3 January 2006), http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/, accessed 18 January 2008.

8.1-17 Michigan Public Service Commission, “Comments Received on Electric Energy Policy,” (12 September 2006), http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/strawmanpolicycomments_sept12_2006.pdf, accessed 18 January 2008.

8.1-18 Granholm, J.M., Governor, State of Michigan, “21st Century Energy Plan,” Executive Directive No. 2006-02, http://www.michigan.gov/gov/0,1607,7-168-36898-140415--,00.html, accessed 9 July 2008.

Table 8.1-1 Sales Information by Rate Class Sales by Rate Class (MW-hr)

	Detroit Edison				State of Michigan			
Year	Residential	Commercial	Industrial	Total	Residential	Commercial	Industrial	Total
2002	15,957,874	18,395,314	13,589,485	47,942,673	34,336,161	38,535,336	35,382,660	108,254,157
2003	15,074,412	16,343,669	19,534,706	50,952,787	33,669,474	36,259,004	49,057,328	118,985,806
2004	15,082,838	20,052,785	14,682,081	49,817,704	33,104,834	46,553,277	40,936,199	120,594,310
2005	16,813,387	20,809,664	14,401,764	52,024,815	36,096,383	46,191,922	39,485,097	121,773,402
2006	15,769,599	20,497,463	14,287,400	50,554,462	34,622,376	42,208,503	36,802,211	113,633,090

Source: Reference 8.1-12

Table 8.1-2 Sales Information by Rate Class Customer Count by Rate Class

	Detroit Edison				State of Michigan			
Year	Residential	Commercial	Industrial	Total	Residential	Commercial	Industrial	Total
2002	1,945,275	184,149	1,015	2,130,439	4,188,117	487,029	14,869	4,690,015
2003	1,952,000	181,462	910	2,134,372	4,216,573	483,662	14,358	4,714,593
2004	1,967,037	191,975	1,128	2,160,140	4,248,984	520,702	14,901	4,784,587
2005	1,977,080	194,178	1,160	2,172,418	4,284,150	527,018	13,918	4,825,086
2006	1,977,032	196,628	1,139	2,174,799	4,299,286	520,448	13,485	4,833,219

Source: Reference 8.1-12

Table 8.1-3 Sales Information by Rate Class Average Sales per Customer (MW-hr)

	Detroit Edison				State of Michigan			
Year	Residential	Commercial	Industrial	Total	Residential	Commercial	Industrial	Total
2002	8	100	13,389	23	8	79	2,380	23
2003	8	90	21,467	24	8	75	3,417	25
2004	8	104	13,016	23	8	89	2,747	25
2005	9	107	12,415	24	8	88	2,837	25
2006	8	104	12,544	23	8	81	2,729	24

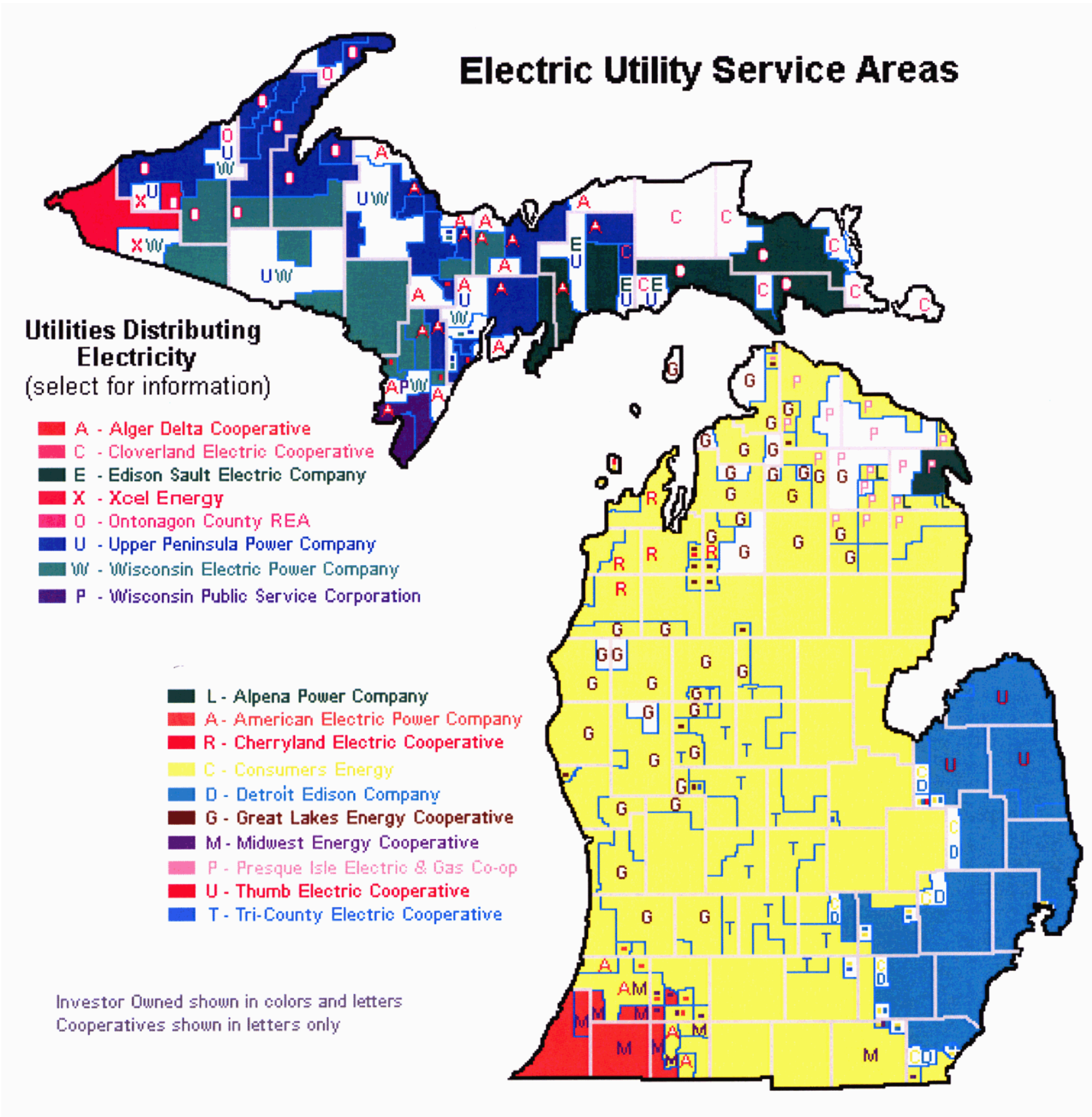
Source: Reference 8.1-12

Table 8.1-4 Sales Information by Rate Class % of Total MW-hr by Rate Class

	Detroit Edison				State of Michigan			
Year	Residential	Commercial	Industrial	Total	Residential	Commercial	Industrial	Total
2002	33%	38%	28%	100%	32%	36%	33%	100%
2003	30%	32%	38%	100%	28%	30%	41%	100%
2004	30%	40%	29%	100%	27%	39%	34%	100%
2005	32%	40%	28%	100%	30%	38%	32%	100%
2006	31%	41%	28%	100%	30%	37%	32%	100%

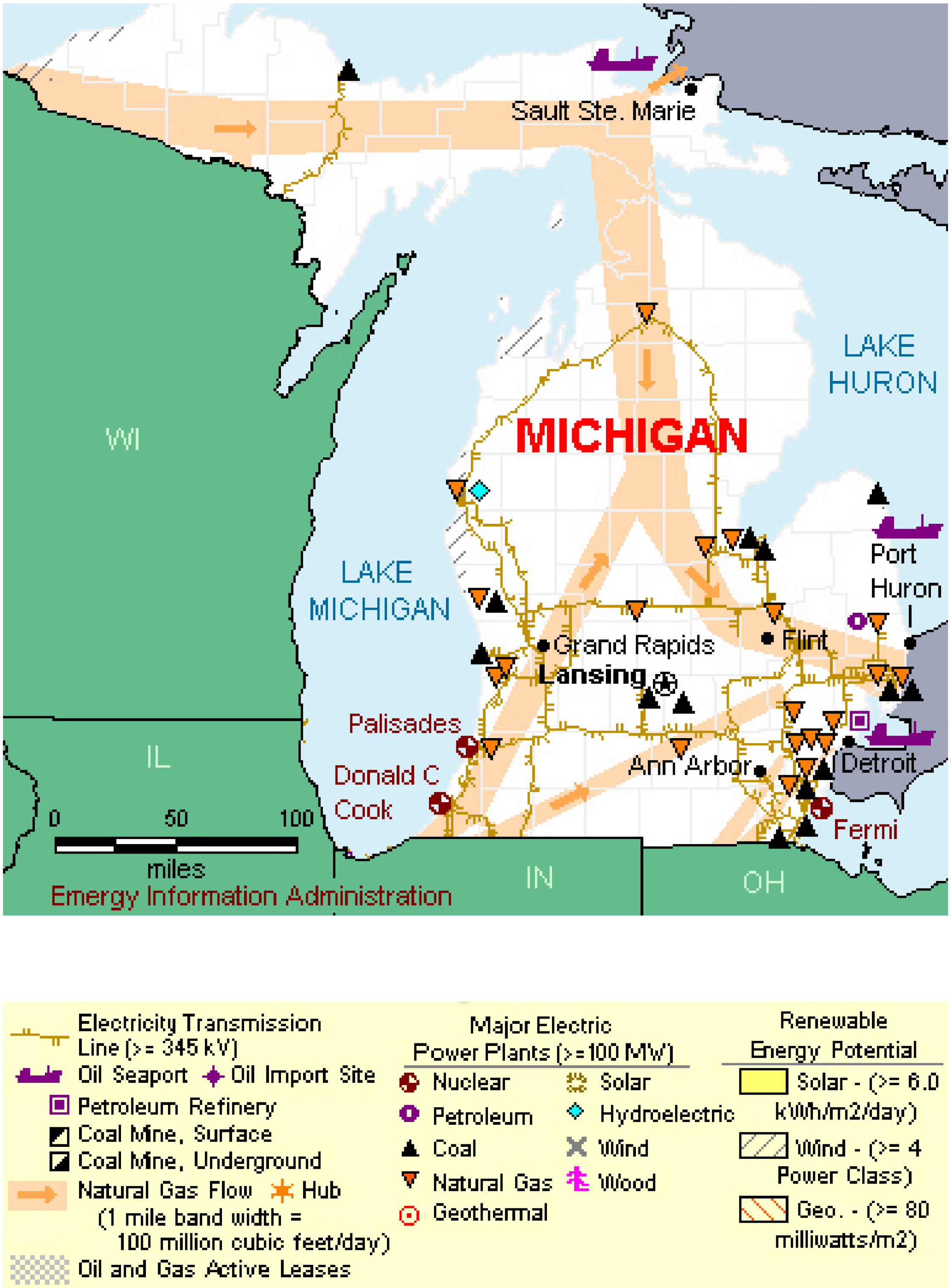
Source: Reference 8.1-12

Figure 8.1-1 Michigan Electric Utility Service Areas



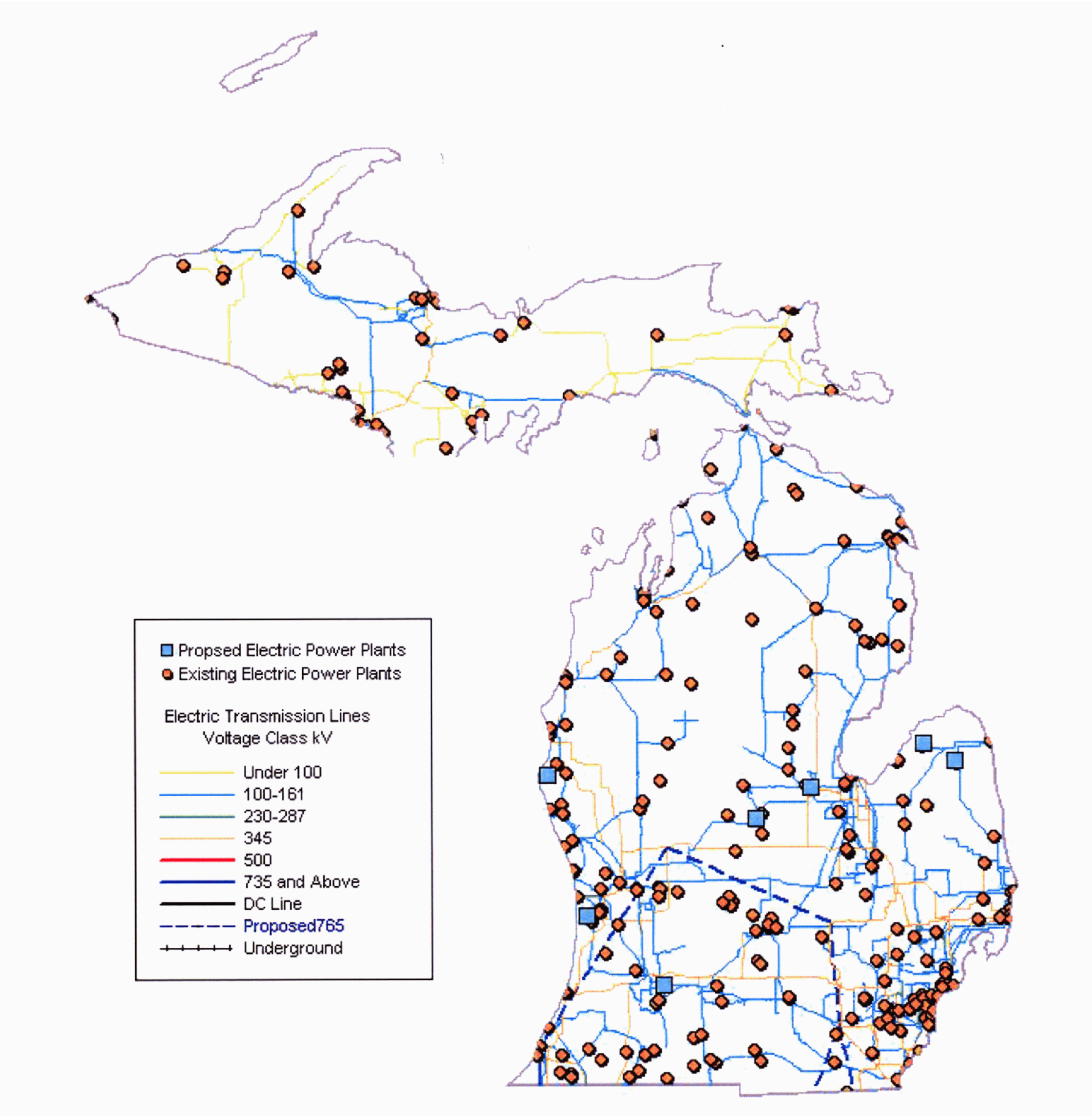
Source: Reference 8.1-3

Figure 8.1-2 Michigan Electric Generation and Grid Network



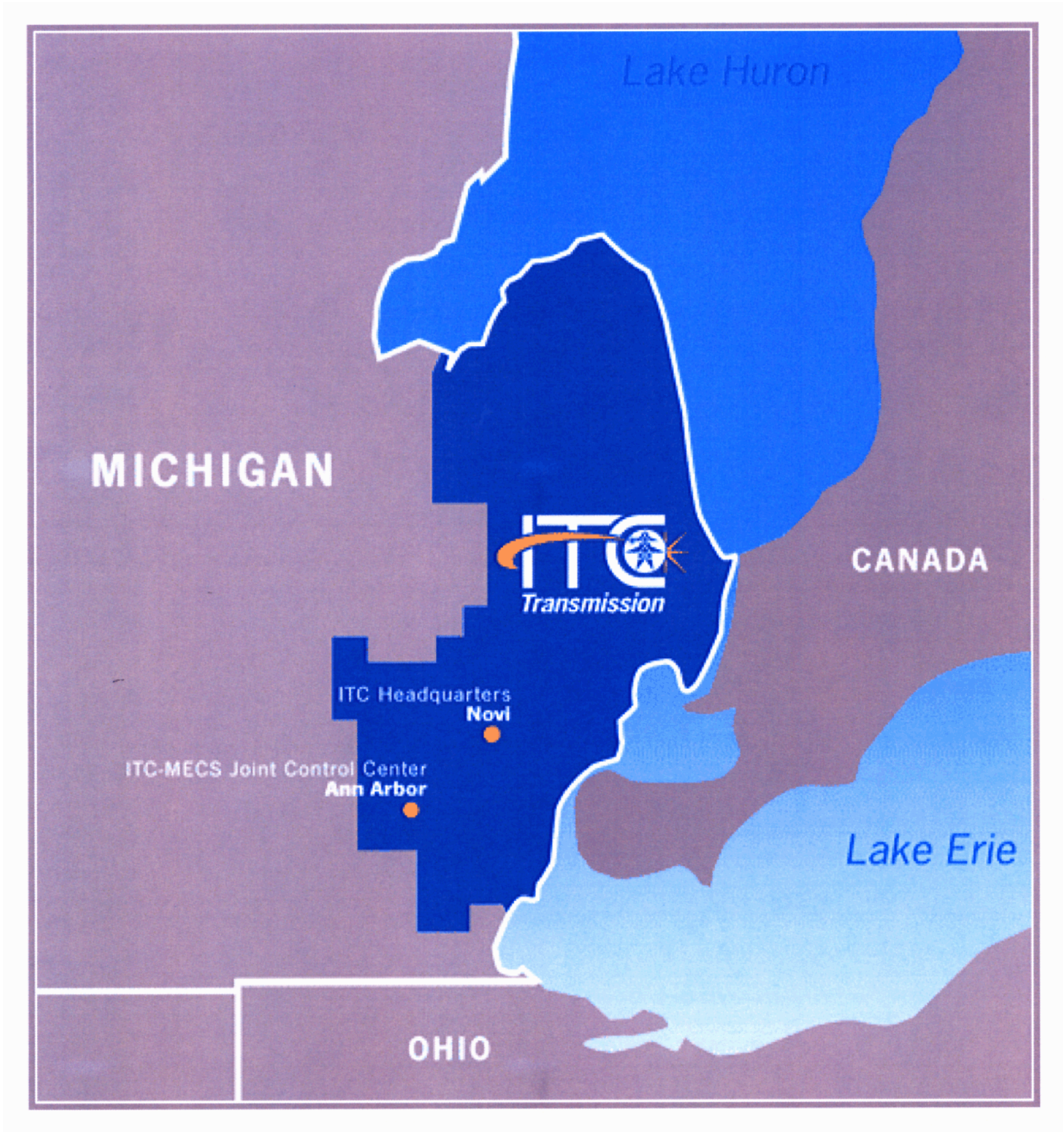
Source: Reference 8.1-4

Figure 8.1-3 Michigan Transmission Lines



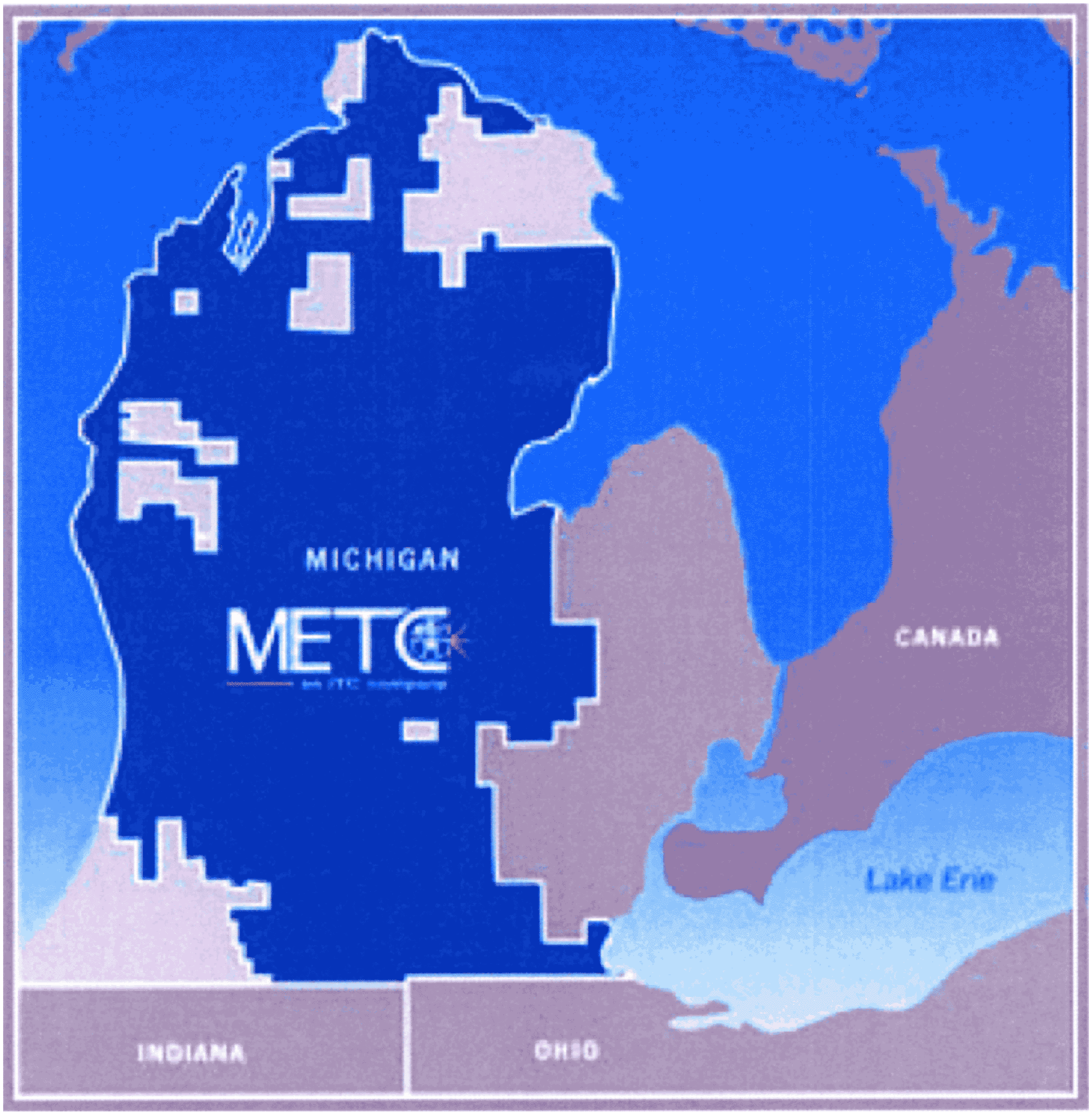
Source: Reference 8.1-5

Figure 8.1-4 ITC*Transmission* Service Area



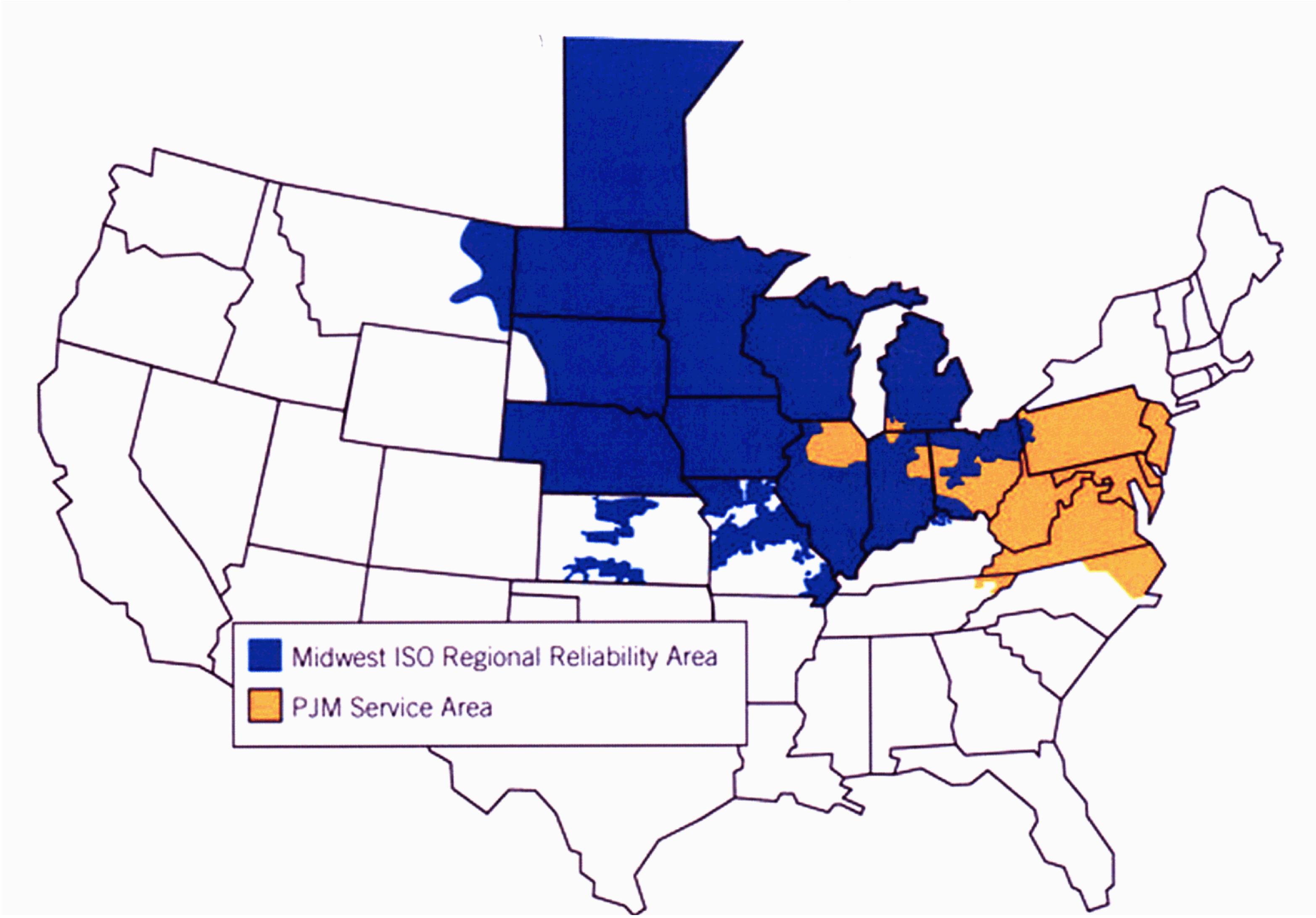
Source: Reference 8.1-7

Figure 8.1-5 METC Service Area



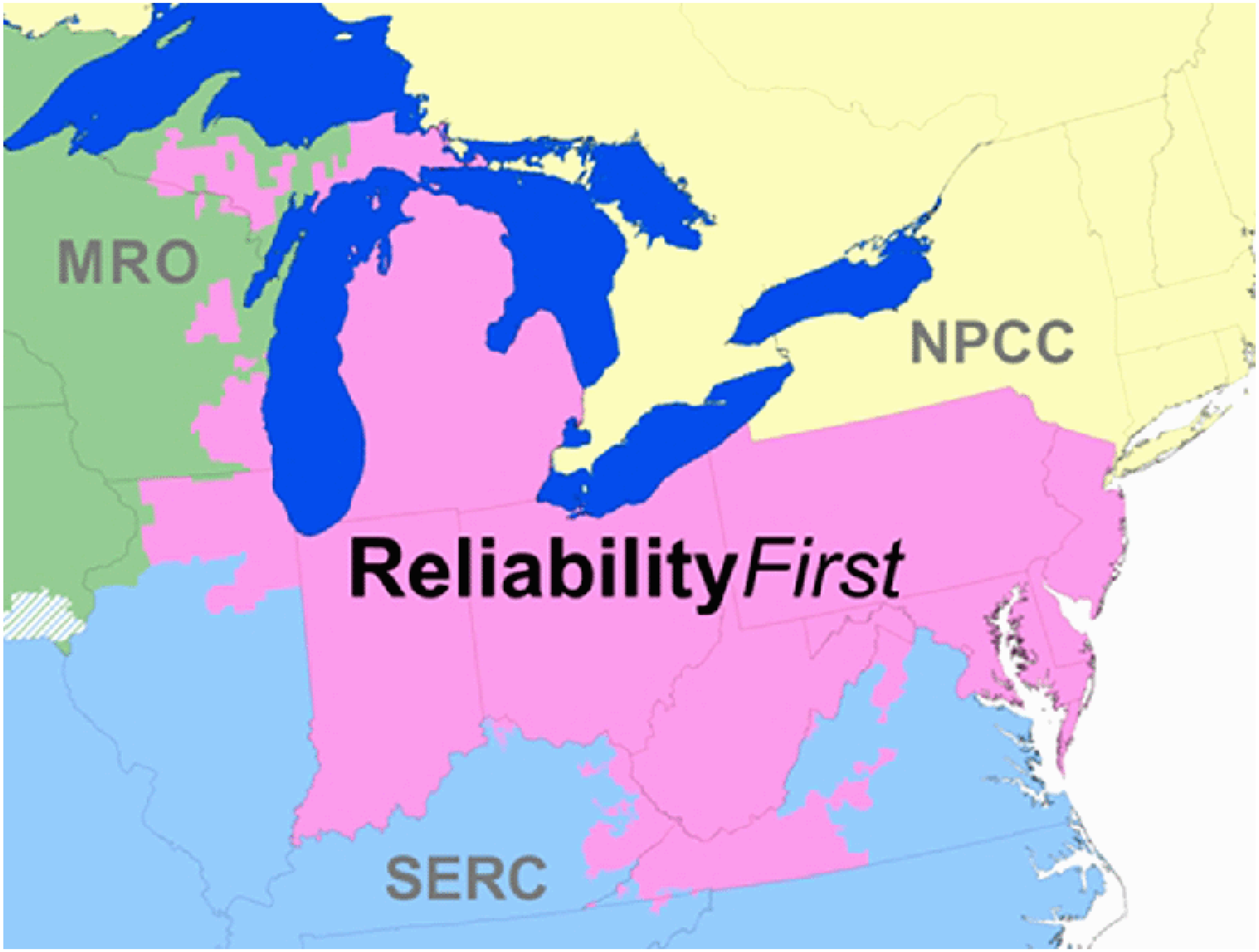
Source: Reference 8.1-9

Figure 8.1-6 Midwest ISO Regional Reliability Area and PJM Service Areas



Source: Reference 8.1-10

Figure 8.1-7 Reliability*First* Service Area



Source: Reference 8.1-14

8.2 Power Demand

The electrical power distribution system considered in this need for power evaluation is described in Section 8.1, including the service area considered. As discussed in Section 8.1, for the purposes of this need for power evaluation, the approximate target schedule for commercial operation is the 2nd quarter of 2020.

Electricity provided the power by which Henry Ford and other manufacturing pioneers transitioned Michigan's 19th Century agricultural economy into a 20th Century industrial leader. In the 21st Century, electricity will continue to play a vital role in the transition of Michigan's economy into the digital age. Regulatory and energy providers must ensure that the electrical supply necessary to power Michigan through the next two decades is readily available, providing safe, reliable, affordable, and efficient power. To meet that goal, on April 6, 2006 the Governor of the State of Michigan signed Executive Directive No. 2006-02 (Reference 8.2-4), directing the chairman of the Michigan Public Service Commission to prepare a 21st Century Electric Energy Plan – a comprehensive energy plan to address the short and long term electric needs of the citizens of Michigan (Reference 8.2-1). As Executive Directive No. 2006-02 states, a reliable, safe, clean, and affordable supply of energy is critical to the public good.

Subsection 8.2.1 provides a high level overview of the information pertinent to power demand extracted from the Michigan 21st Century Electric Energy Plan. The input to the tables, figures, and data present in this section are derived from the plan. The methodology is briefly described, highlighting the major aspects involved in producing the forecasts, including the data input used in the process. A historical perspective of the load growth in the region is provided, and final results of the forecast peak demands and energy consumption are presented in graphical form and tabular summary. This section includes a discussion of the major drivers of peak demands and energy consumption. Subsection 8.2.2 addresses forecasting uncertainties and the potential reductions in energy demand that could be realized with an effective energy efficiency program.

The long range electrical demand forecasts discussed in this section represent the aggregate product of individual forecasts made by investor-owned, municipal, and cooperative utilities. The forecasts were developed using accepted techniques and employed a wide range of explanatory variables. The Michigan 21st Century Electric Energy Plan was developed using several different teams working together to complete the effort, including load forecasting performed by the Capacity Need Forum Update Workgroup. The methodology utilized for plan development subjected overall forecasts to numerous reviews. This method of development and review by multiple parties provided an independent assessment of the forecast electrical consumption.

8.2.1 **Power and Energy Requirements**

8.2.1.1 **Historical Data**

Figure 8.2-1 provides the annual electric sales for the State of Michigan for the time period of 1990 through 2004. The information shown in Figure 8.2-1 is also provided in Table 8.2-1. Table 8.2-1 provides the annual electric sales for each of three regions of the State of Michigan considered (Southeastern Michigan, Balance of Lower Peninsula, and Upper Peninsula) with the overall percentage change for the total annual sales. Figure 8.2-1 shows the summation for the annual sales of each of the three regions.

The historical peak demand for the State of Michigan for the time period of 1990 through 2004 is shown graphically in Figure 8.2-2. The information shown in Figure 8.2-2 is also provided in Table 8.2-2. Table 8.2-2 provides the peak demand for each of three regions of the State of Michigan considered (Southeastern Michigan, Balance of Lower Peninsula, and Upper Peninsula) with the overall percentage change for the peak demand. Figure 8.2-2 shows the summation for the peak demand of each of the three regions.

8.2.1.2 **Long Term Forecast Methodology**

In early 2006, the Staff of the Michigan Public Service Commission issued a report on the Capacity Need Forum (CNF) (Reference 8.2-2). One of the stated topics of the CNF was to address the anticipated short term, intermediate term, and long term demand for power. To address this topic, the development of the CNF included a Demand Work Group. The Demand Work Group was responsible for developing a consensus-based 20 year forecast (2006 through 2025) of electrical energy and peak demand for each of the three designated regions (Southeastern Michigan, Balance of Lower Peninsula, and Upper Peninsula). The report from the Demand Work Group is contained as Appendix D to the CNF study report.

The demand and energy forecasts used by the Demand Work Group represented the aggregate product of individual forecasts made by investor-owned, municipal, and cooperative utilities. Southeast Michigan's forecast is based almost exclusively on Detroit Edison's projections. Detroit Edison makes use of econometric estimation models for a five to ten year period, and then uses growth rates produced by those models to project future sales. The economic parameter forecast was created by DTE Energy's corporate economist and is based upon data and forecasts from Global Insight and Blue Chip Economic Indicators. The economic parameters of Detroit Edison's forecast include:

- U.S. and Detroit car and truck production,
- Detroit steel production,
- Detroit and Ann Arbor non-manufacturing employment,
- Detroit index of coincident indicators,
- U.S. Federal Reserve Bulletin (FRB) industrial production index, and
- Detroit and Ann Arbor housing permits.

The forecast of the balance of the Lower Peninsula includes Consumers Energy, Wolverine Power Cooperative, municipal utilities, and several other utilities, with Consumers Energy forecast contributing the majority of the forecasted load. The Upper Peninsula's forecast reflects the aggregation of several investor-owned utilities and municipal utilities.

As previously discussed, four different Workgroups contributed to the development of the 21st Century Energy Plan. One of these four Workgroups was the Capacity Need Forum Update

Workgroup. The Capacity Need Forum Update Workgroup included several Teams; one of these Teams was the Demand Team. The Demand Team was charged with preparing an annual electric demand and energy forecast for the period 2006 through 2025 for the CNF Update Workgroup.

The forecast is not an independent projection made by the Demand Team. Rather the projected requirements and peak demands and annual energy requirements are a compilation of forecasts prepared by each Michigan utility. Individual projections obtained for all investor owned, cooperative, and municipal utilities in Michigan were compiled and aggregated into the three geographic areas used in the plan analyses: Southeast Michigan, Balance of Lower Peninsula, and Upper Peninsula. These three geographic areas correspond to electric transmission operating areas. First, Southeast Michigan comprises the area served by ITC*Transmission*. Second, the balance of the Lower Peninsula excluding the Indiana & Michigan Power Company (I&M) service territory is the general area served primarily by METC, Wolverine Power Supply Cooperative, Inc. (Wolverine), and certain municipal cities of the Michigan Public Power Agency (MPPA). The Upper Peninsula, the third area, is served by the American Transmission Company.

The purpose of the forecast is to provide demand and energy projections for use in modeling the State of Michigan's electric generation and transmission resource needs in the near and longer term future. The forecast is also an input into the assessment of electric reliability in Michigan, which is determined by the Midwest ISO using a Multi-Area Reliability Module (MARELI) computer model. The MARELI model is a probability based algorithm used to assess whether a geographic region's native generation, together with interruptible load and impact capability, is sufficient to meet hourly peak loads, with the specified loss of load probability (LOLP) tolerance.

The energy modeling methodologies use various scenarios and sensitivities to evaluate a variety of risks and uncertainties, which generally arise from the need to project energy requirements quite far into the future. It is a common feature of energy plans to create scenarios and sensitivities to account for the uncertainty to electric demand forecasts. The CNF utilized scenarios and sensitivities in its modeling. High Growth and Low Growth scenarios were developed for risk analysis purposes. It is understood that actual future electricity demand will be higher or lower than the Base Case forecast. The actual course of future electricity demand will depend on numerous factors: economic conditions and growth, population growth and demographic change, and weather variances from the assumed normal weather that typically is used for a base forecast. The purpose of the High Growth and Low Growth scenario risk analyses are to attempt to envelope these factors. The risk analyses were performed using a formulistic approach, and each scenario is developed from the Base Case, which is the composite of the utility forecasts. The High Growth and Low Growth scenarios are symmetric around the Base Case.

- The High Growth scenario is 2.0 percent higher in the first projection year – 2006; 3.0 percent higher in the second projection year – 2007; 4.0 percent higher in the third year, and so on through 2015 when the High Growth scenario reaches 10.0 percent higher than the Base Case. The High Growth scenario is then held at 10.0 percent higher than the Base Case for the remainder of the projection period.

- The Low Growth scenario is derived identically to the High Growth scenario, except that it is 2.0 percent lower, 3.0 percent lower, and so on from the Base Case, then held a constant 10.0 percent lower for years 2015 through 2025.

The CNF study report noted that the auto and truck industry drives much of southeast Michigan's manufacturing demand for electricity and that the "longer-term future growth of this sector is clouded." Detroit Edison's and Consumers Energy's latest projections reflect the result of a closer review of recent sales trends and revised expectations pertaining to Michigan's motor vehicle industry. Both companies have revised the outlook for Michigan's motor vehicle industry downward, and this has lowered the projected sales and system peak demands. In addition, both companies have reviewed recent appliance saturation information, and now show lower growth due to service territory air conditioning markets that are already nearly saturated.

Detroit Edison's electricity projections are based on econometric and end-use modeling techniques and the forecast is based upon an economic projection produced by the company.

8.2.1.3 **Results of Long Term Forecast**

As noted above, electricity requirements and peak demand projections were aggregated to three geographic regions in the State of Michigan: Southeast Michigan, Balance of Lower Peninsula, and the Upper Peninsula. The relative electricity market size of these regions is shown in Figure 8.2-3, depicting forecasted gigawatt-hour (GWh) electric generation requirements by region for the year 2008.

The 21st Century Plan forecasted Michigan's total electric generation requirements to grow at an annual average rate of 1.3 percent from 2006 to 2025, from 112,183 GWh to 143,094 GWh. Southeast Michigan's generation requirements were forecasted to grow an average of 1.2 percent annually, and annual growth for the balance of the Lower Peninsula was forecasted to average 1.4 percent. The Upper Peninsula's annual average growth rate was forecasted at 0.9 percent for this period.

Projected electric generation requirements are shown on Figure 8.2-4. Table 8.2-3 provides the details of the forecast by State regions for the Base Case scenario. For comparison purposes, Figure 8.2-4 includes the projected electrical generation requirements for the High Growth and Low Growth scenarios. Table 8.2-4 provides the details of the forecast by State region for the High Growth scenario. Table 8.2-5 provides the details of the forecast by State region for the Low Growth scenario.

The plan forecasts summer peak electricity demand to grow from 23,756 MW in 2006 to 29,856 MW in 2025, an annual average rate of growth of 1.2 percent. The forecasted peak load growth for Southeast Michigan is 1.2 percent per year, for the Balance of the Lower Peninsula it is 1.2 percent, and for the Upper Peninsula it is 0.9 percent. Forecasted peak demand growth for the Base Case, High Growth scenario, and Low Growth scenario are shown in Figure 8.2-5. Table 8.2-6 provides the details of the forecast by State region for the Base Case. Table 8.2-7 provides the details of the forecast by State region for the High Growth scenario. Table 8.2-8 provides the details of the forecast by State region for the Low Growth scenario.

The forecasting results from the 21st Century Plan were compared to the results from the CNF study report. To summarize for the Base Case,

- The CNF study report forecasted an increase in annual electric energy consumption from 113,782 GWH in 2005 to 163,411 GWh in 2025. This reflected a statewide average growth rate of 1.9 percent.
- The CNF study report forecasted peak demand to grow from 24,101 MW in 2005 to 36,589 MW in 2025, an average annual growth rate of 2.1 percent. Peak demand was forecasted to grow at 1.7 percent annually in the ITC*Transmission* region, 2.7 percent in the METC region, and 0.9 percent in the Upper Peninsula.

  Michigan peak demand in the Base Case in the plan is forecasted to grow 1.2 percent annually for 2006 through 2025 as compared to 2.1 percent annually in the CNF study report. As one would expect, growth in energy requirements is similarly lower. Energy requirements for 2006 through 2025 grow at 1.3 percent annually compared to 1.9 percent in the CNF study report. These differences are shown graphically on Figure 8.2-6.

  The differences in the forecasts from the 21st Century Plan to those from the CNF study report reflect a lower than expected growth in the Michigan economy and lower growth in saturation of electrical appliances. Generally, the outlook in the 21st Century Plan , as compared to the CNF study report projection:

  1. Reflects a revised and lower growth projection by Detroit Edison,
  2. Reflects a revised and lower growth projection by Consumer's Energy, and
  3. Is relatively unchanged for the remaining Michigan utilities.

8.2.2 Factors Affecting Growth of Demand

It is recognized that the actual future electricity demand will most likely be higher or lower than the Base Case forecast in the 21st Century Plan. As discussed above, in order to assess how robust the selected resource plan is to changes in the growth rate of electric demand, the plan provides a base forecast along with more rapid growth and slower growth forecast.

Subsection 8.2.1.2 discusses the inputs to the demand forecasting models, which include factors that could affect load growth. These inputs include projections for demographic information such as the industrial, commercial, and residential sectors. Specific measurements and projections include car and truck production, steel production, non-manufacturing employment, and housing starts. More detail regarding projections for population demographics are provided in Subsection 2.5.1.

The actual course of future demand will be dependent upon numerous factors: economic conditions and growth, population growth and demographic change, and weather variances from the assumed normal weather pattern that typically is used for a base forecast. If one anticipates normal weather, economic and customer growth will likely drive the eventual growth of electricity sales and resulting system requirements in Michigan. A number of participants in the Work Groups that developed the plan indicated that growth is likely to be affected by manufacturing output and employment in

Michigan. Manufacturing employment is heavily related to the auto and truck industry, which in addition to experiencing business cycles is facing stiff international competition. These projections influenced the forecast in the 21st Century Plan resulting in the reduced growth forecast as compared to that in the CNF study report. This reduced growth forecast is discussed in more detail, above, in Subsection 8.2.1.3.

8.2.2.1 Forecast Uncertainties

Four basic sources of potential uncertainties in the forecast are discussed in more detail in the 21st Century Plan. First, the utility forecasts assume some sort of normal weather for both sales and system peak demand projections. Second, the forecasts typically do not attempt to capture business cycle impacts, albeit many projections will attempt to capture the cycle for the first year or two of the forecast period. Third, the trends in economic conditions are difficult to project but remain critical input into determining future electricity needs. Fourth, the penetration of electricity devices in consumer markets, including the market penetration of new products and other services that require electricity, remains a very difficult component to predict. Each of these four factors and how they relate to the forecasts are discussed in more detail below.

- Weather is generally assumed to be normal for each year over the forecast period, and peak system demand day projections typically assume weather mimicking some historic average system peak day weather. During the summer of 2006, Michigan utilities experienced record system peak demands, and the peaks for Consumers Energy and Detroit Edison were higher than those forecasted for 2006 (same forecast that is used in the plan).

  In any event, year-to-year difference in electricity requirements stemming from assumed weather varying from actual weather is viewed as an inconsequential issue for long term resource planning. But, questions always arise about the nature of the most recent forecast errors, or perceived errors, in a projection, and whether the errors are sufficient to void or hold suspect the entire forecast. Record peak demands achieved during the summer of 2006 and a review of the actual peaks compared to projections is illustrative.

  Detroit Edison's projected peak for 2006 was 12,577 MW. Detroit Edison's 2006 actual summer peak of 12,778 MW occurred on August 1. On this day, approximately 313 MW of load was reduced or interrupted, and without these reductions the peak would have been 13,091 MW according to a preliminary analysis completed by Detroit Edison. This potential peak would have been 514 MW above the forecasted peak.

  Detroit Edison's forecasting process uses a peak day average temperature of 83.0 degrees Fahrenheit, which is based on daily temperatures of Detroit Edison's historic peak summer demand days. On August 2, 2006, the average daily temperature was 86.5 degrees Fahrenheit, 3.5 degrees higher than the design temperature of the forecast. Detroit Edison's review of the 2006 summer peak, using that day and other actual peak days of the 2006 summer, shows its peak estimate (without interruptions) at 83.0 degrees Fahrenheit would be 12,588 MW, extremely close to its projection of 12,577 MW.

As concluded in the plan, the 2006 actual peaks were impacted by above normal hot weather and are not evidence suggesting errors in the initial year forecasts that would impact capacity planning.

- The second area of uncertainty stems from failure to capture the business cycle, or from simply trending the projection and, therefore, explicitly ignoring the cycle. While the first year or two of these forecasts can generally be regarded as a near term outlook intended to capture current economic conditions, the longer term forecast is a trend projection that does not intend to capture cyclical economic conditions. As concluded in the plan, this is not considered a concern for long term electricity resource requirements analyses, since these errors tend to off-set each other and be diluted over time.
- The third area of potential uncertainty is the assessment of future economic conditions. As discussed in the plan, manufacturing output and employment in Michigan, especially in the motor vehicle industry, remains a major factor affecting electricity requirements and remains a major uncertainty. The past several years have witnessed a steady erosion of Michigan's motor vehicle industry share of national sales and output. The lower electricity sales growth experienced by Detroit Edison and Consumers Energy reflects a significant departure from recent forecasts by these companies, and is based on recent trends, known events, and the ever-increasing awareness that Michigan may be greatly affected by restructuring of auto firms based in Michigan.
- The fourth area of potential uncertainty is the consumer market for electric appliances. This may be broadly construed to include residential equipment and commercial and industrial equipment. Current electricity use can be impacted by potential electricity substitution (for example, replacing an electric hot water heater with a natural gas fired hot water heater). Equipment and buyer acceptance (market penetration) of the equipment, such as air conditioning, can impact future electricity use. Efficiency of electrical appliances will also affect electricity use. This is discussed in more detail in Subsection 8.2.2.2, below. Projecting changes in electricity demand requirements due to known new equipment technologies, and especially to equipment which may not even be on the market today, remains a difficult aspect of forecasting electricity requirements.

Forecasting uncertainties are intended to be captured by the sensitivity analyses performed around the Base Case with ample consideration given to Low Growth and High Growth scenarios.

8.2.2.2 **Energy Efficiency and Conservation**

In addition to the four factors discussed above, demand growth can be affected by increased energy efficiency and conservation. Energy efficiency is defined in Reference 8.2-3 as follows:

> Energy efficiency refers to using less energy to provide the same or improved level of service to the energy consumer in an economically efficient way. The term energy efficiency as used here includes using less energy at any time, including at times of peak demand through demand response and peak shaving efforts.

Energy efficiency should be distinguished from energy conservation in that energy efficiency is a proactive and technology-driven process while energy conservation is a usage-driven process that results in the direct scaling back of energy consumption. When aggressively pursued, conservation may imply a reduced level of energy service, whereas energy efficiency attempts to maintain or improve energy services while at the same time using less energy. Another distinction between energy efficiency and energy conservation is that conservation tends to be a reactive and temporary measure associated with high energy prices and adverse economic conditions.

Energy efficiency was examined as part of the work associated with the 21st Century Plan. Four major categories of energy efficiency were assessed.

1. Statewide energy efficiency program,
2. Electric utility load response program,
3. Commercial building code update,
4. State specific energy efficiency standards for appliances.

As discussed above, and in detail in the plan, the Energy Efficiency Workgroup studied four categories to determine the energy efficiency for the State of Michigan. The assessment of these categories resulted in an estimated statewide potential savings shown in Table 8.2-9 and Table 8.2-10.

Estimates of energy and demand savings and program costs were developed using a sufficiently rigorous approach for the purposes of developing policy directions. The results of the Michigan energy efficiency study suggest that Michigan could implement a new statewide electric energy efficiency program having considerable scope and impact on electric use in Michigan. Based on the study, an aggressive program could reduce the projected growth rate in Michigan electric energy use (1.2 percent – as discussed above) by more than 50 percent over a 10 year period. The energy efficiency model estimated that after 10 years of energy efficiency programming, electric energy use in Michigan could be reduced within a range of 6664 gigawatt hours (GWh) to 10,603 GWh. Electric peak demand could be reduced, over the same 10 year period, within a range of 876 MW to 1889 MW.

Peak load reductions can be reduced by expanding the scope of residential and small commercial electric load response programs. Consumers Energy and Detroit Edison have conservatively estimated that a 10 year load management programming effort could reduce Michigan electric peak demand by 569 MW and annual energy use by 35 GWh.

The Energy Efficiency Workgroup also investigated the impact of updating Michigan's commercial building code and concluded that in the 10th year of a code update, annual electric energy savings of 477 GWh could be obtained and peak demand could be reduced by 99 MW. As discussed in the plan, the implementation of a new Michigan commercial building code was determined to result in an overall reduction to expected commercial building costs, according to a September 2006 study prepared for the U.S. Department of Energy. The overall results of energy efficiency and demand response modeling are summarized in Appendix II, Chapter 3 of the plan.

State appliance standards were briefly assessed. Estimates made for the Workgroup suggest that if Michigan instituted its own standards on the several appliances that are not currently under federal standards, significant electric energy savings could be realized.

The energy efficiency assessment is discussed in more detail in Chapter 3 of Volume II. Chapter 3 discusses the approach and methodology taken to address energy efficiency, and the scope of the evaluation. The various tests used to measure the benefits and costs of energy efficiency from several different perspectives are discussed and provide useful information for determining the scope and type of energy efficiency programming that may be appropriate for a statewide program. The type of benefit/cost test chosen as an economic basis for program planning has a direct effect on the estimated level of achievable energy savings. This modeling effect comes about because the chosen category of benefit/cost test determines the type, and thus the level, of costs input into that portion of the modeling process that is concerned with scaling individual market scope.

Prior to the development of the 21st Century Plan, the State of Michigan did not have a comprehensive energy efficiency program. One of the recommendations in the plan was that the Michigan Public Service Commission be authorized to create the Michigan Energy Efficiency Program. It is noted that the Michigan State government is already carrying out a Statewide program pursuant to Governor Grandholm’s Executive Directive No. 2005-04, Energy Efficiency in State Facilities and operations, which required reduced energy use in State buildings, and promoted use of energy efficiency measures in State purchasing.

8.2.3 References

8.2-1 Lark, J. Peter, Chairman Michigan Public Service Commission, “Michigan’s 21st Century Electric Energy Plan,” Submitted to Honorable Jennifer M. Granholm, Governor of Michigan, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm, accessed 18 January 2008.

8.2-2 Stojic, George, Director Operations & Wholesale Markets Division, to Michigan Public Service Commission, Chairman J. Peter lark, Commissioner Laura Chappelle, and Commissioner Monica Martinez, “Final Staff Report of the Capacity Need Forum,” (3 January 2006), http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/, accessed 18 January 2008.

8.2-3 U.S. Environmental Protection Agency, “National Action Plan for Energy Efficiency,” (July 2006), http://www.epa.gov/cleanrgy/documents/napee/napee_report.pdf, accessed 18 January 2008.

8.2-4 Granholm, J.M., Governor, State of Michigan, “21st Century Energy Plan,” Executive Directive No. 2006-02, http://www.michigan.gov/gov/0,1607,7-168-36898-140415--,00.html, accessed 9 July 2008.

Table 8.2-1 Annual Electric Sales (1990 – 2004) Units are in Gigawatt-hours (GWh)

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Sales	Percent Change
1990	39,674	37,716	4,183	81,573	N/A
1991	40,135	38,851	4,838	83,824	2.8%
1992	39,377	39,411	5,052	83,840	0.0%
1993	41,716	40,992	4,880	87,588	4.5%
1994	43,211	42,667	5,281	91,159	4.1%
1995	44,926	44,385	5,390	94,701	3.9%
1996	45,328	45,407	5,567	96,302	1.7%
1997	45,822	45,990	5,578	97,390	1.1%
1998	47,905	46,899	5,702	100,506	3.2%
1999	49,822	48,582	5,577	103,981	3.5%
2000	50,211	48,836	5,839	104,886	0.9%
2001	49,370	49,033	5,415	103,818	-1.0%
2002	51,650	50,695	5,873	108,218	4.2%
2003	50,953	49,898	5,940	106,791	-1.3%
2004	50,268	51,113	6,040	107,421	0.6%

Source: Reference 8.2-2, Appendix D, Attachment II, Table II-1

Table 8.2-2 Peak Demand (1990 – 2004) Units are in Megawatts (MW)

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Demand	Percent Change
1990	9,032	8,071	950	18,053	N/A
1991	8,980	8,317	997	18,294	1.3%
1992	8,704	8,121	1,002	17,827	-2.6%
1993	9,362	8,512	950	18,824	5.6%
1994	9,684	8,723	1,040	19,447	3.3%
1995	10,049	9,553	1,098	20,700	6.4%
1996	10,377	9,593	1,118	21,088	1.9%
1997	10,305	9,875	1,055	21,235	0.7%
1998	10,704	9,920	1,115	21,739	2.4%
1999	11,018	10,144	1,152	22,314	2.6%
2000	10,958	9,946	1,169	22,073	-1.1%
2001	12,240	11,102	1,205	24,547	11.2%
2002	11,308	11,907	1,171	24,386	-0.7%
2003	10,470	12,115	1,220	23,805	-2.4%
2004	12,714	11,575	1,258	25,547	7.3%

Source: Reference 8.2-2, Appendix D, Attachment I, Table I-1

Table 8.2-3 Annual Sales Forecast - Base Case Units are in Gigawatt-hours (GWh)

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Sales	Percent Change
2005	56,859	49,906	6,448	113,213	N/A
2006	55,417	50,240	6,526	112,183	-0.9%
2007	55,606	50,850	6,565	113,021	0.7%
2008	55,967	51,901	6,624	114,492	1.3%
2009	55,839	52,888	6,684	115,411	0.8%
2010	56,454	53,693	6,754	116,901	1.3%
2011	57,130	54,491	6,821	118,442	1.3%
2012	58,003	55,366	6,875	120,244	1.5%
2013	58,718	56,038	6,929	121,685	1.2%
2014	59,569	56,837	6,991	123,397	1.4%
2015	60,304	57,665	7,053	125,022	1.3%
2016	61,073	58,622	7,116	126,811	1.4%
2017	61,830	59,170	7,180	128,180	1.1%
2018	62,780	59,959	7,243	129,982	1.4%
2019	63,717	60,752	7,306	131,775	1.4%
2020	64,674	61,677	7,370	133,721	1.5%
2021	65,647	62,375	7,434	135,456	1.3%
2022	66,635	63,195	7,499	137,329	1.4%
2023	67,641	64,021	7,564	139,226	1.4%
2024	68,662	64,972	7,632	141,266	1.5%
2025	69,701	65,692	7,701	143,094	1.3%

Source: Reference 8.2-1, Volume II, Chapter 2, Table 7

Table 8.2-4 Annual Sales Forecast – High Growth Scenario Units are in Gigawatt-hours (GWh)

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Sales	Percent Change
2005	57,427	50,405	6,513	114,345	N/A
2006	56,525	51,245	6,657	114,427	0.1%
2007	57,274	52,375	6,762	116,411	1.7%
2008	58,206	53,977	6,889	119,072	2.3%
2009	58,631	55,532	7,018	121,181	1.8%
2010	59,841	56,915	7,160	123,916	2.3%
2011	61,129	58,305	7,299	126,733	2.3%
2012	62,644	59,796	7,425	129,865	2.5%
2013	64,003	61,081	7,552	132,636	2.1%
2014	65,526	62,520	7,690	135,736	2.3%
2015	66,335	63,431	7,759	137,525	1.3%
2016	67,180	64,484	7,828	139,492	1.4%
2017	68,013	65,087	7,897	140,997	1.1%
2018	69,058	65,955	7,967	142,980	1.4%
2019	70,089	66,827	8,037	144,953	1.4%
2020	71,141	67,845	8,107	147,093	1.5%
2021	72,211	68,612	8,178	149,001	1.3%
2022	73,299	69,515	8,249	151,063	1.4%
2023	74,405	70,423	8,321	153,149	1.4%
2024	75,529	71,469	8,395	155,393	1.5%
2025	76,672	72,261	8,471	157,404	1.3%

Source: Reference 8.2-1, Volume II, Chapter 2, Table 8

Table 8.2-5 Annual Sales Forecast – Low Growth Scenario Units are in Gigawatt-hours (GWh)

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Sales	Percent Change
2005	56,290	49,407	6,384	112,081	N/A
2006	54,308	49,235	6,396	109,939	-1.9%
2007	53,938	49,324	6,368	109,630	-0.3%
2008	53,728	49,825	6,359	109,912	0.3%
2009	53,047	50,243	6,350	109,640	-0.2%
2010	53,067	50,472	6,349	109,888	0.2%
2011	53,131	50,676	6,344	110,151	0.2%
2012	53,363	50,937	6,325	110,625	0.4%
2013	53,434	50,994	6,305	110,733	0.1%
2014	53,612	51,153	6,292	111,057	0.3%
2015	54,274	51,898	6,348	112,520	1.3%
2016	54,966	52,759	6,405	114,130	1.4%
2017	55,647	53,253	6,462	115,362	1.1%
2018	56,502	53,963	6,519	116,984	1.4%
2019	57,346	54,677	6,575	118,598	1.4%
2020	58,207	55,510	6,633	120,350	1.5%
2021	59,082	56,137	6,691	121,910	1.3%
2022	59,972	56,876	6,749	123,597	1.4%
2023	60,876	57,619	6,808	125,303	1.4%
2024	61,796	58,474	6,869	127,139	1.5%
2025	62,731	59,123	6,931	128,785	1.3%

Source: Reference 8.2-1, Volume II, Chapter 2, Table 9

**Table 8.2-6 Peak Demand Forecast - Base Case
Units are in Megawatts (MW)**

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Peak Demand	Percent Change
2005	12,209	10,420	898	23,527	N/A
2006	12,427	10,426	903	23,756	1.0%
2007	12,579	10,578	910	24,067	1.3%
2008	12,682	10,769	918	24,369	1.3%
2009	12,666	10,972	926	24,564	0.8%
2010	12,806	11,107	938	24,851	1.2%
2011	12,955	11,243	946	25,144	1.2%
2012	13,144	11,374	953	25,471	1.3%
2013	13,287	11,511	962	25,760	1.1%
2014	13,442	11,652	971	26,065	1.2%
2015	13,598	11,794	979	26,371	1.2%
2016	13,728	11,939	988	26,655	1.1%
2017	13,865	12,059	997	26,921	1.0%
2018	14,031	12,198	1,008	27,237	1.2%
2019	14,190	12,337	1,016	27,543	1.1%
2020	14,414	12,476	1,025	27,915	1.4%
2021	14,643	12,617	1,036	28,296	1.4%
2022	14,875	12,758	1,044	28,677	1.3%
2023	15,111	12,900	1,054	29,065	1.4%
2024	15,351	13,044	1,063	29,458	1.4%
2025	15,595	13,188	1,073	29,856	1.4%

Source: Reference 8.2-1, Volume II, Chapter 2, Table 10

Table 8.2-7 Peak Demand Forecast - High Growth Scenario Units are in Megawatts (MW)

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Peak Demand	Percent Change
2005	12,331	10,524	907	23,762	N/A
2006	12,676	10,635	921	24,232	2.0%
2007	12,957	10,895	937	24,789	2.3%
2008	13,190	11,199	954	25,343	2.2%
2009	13,300	11,520	972	25,792	1.8%
2010	13,574	11,774	994	26,342	2.1%
2011	13,861	12,030	1,013	26,904	2.1%
2012	14,196	12,284	1,029	27,509	2.2%
2013	14,483	12,547	1,048	28,078	2.1%
2014	14,786	12,817	1,068	28,671	2.1%
2015	14,958	12,973	1,077	29,008	1.2%
2016	15,101	13,133	1,086	29,320	1.1%
2017	15,252	13,265	1,096	29,613	1.0%
2018	15,434	13,418	1,108	29,960	1.2%
2019	15,609	13,571	1,118	30,298	1.1%
2020	15,856	13,724	1,128	30,708	1.4%
2021	16,107	13,878	1,139	31,124	1.4%
2022	16,362	14,034	1,148	31,544	1.3%
2023	16,622	14,190	1,159	31,971	1.4%
2024	16,886	14,348	1,169	32,403	1.4%
2025	17,154	14,507	1,180	32,841	1.4%

Source: Reference 8.2-1, Volume II, Chapter 2, Table 11

Table 8.2-8 Peak Demand Forecast - Low Growth Scenario Units are in Megawatts (MW)

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Peak Demand	Percent Change
2005	12,087	10,316	889	23,292	N/A
2006	12,178	10,218	885	23,281	0.0%
2007	12,202	10,261	882	23,345	0.3%
2008	12,175	10,338	881	23,394	0.2%
2009	12,033	10,423	879	23,335	-0.3%
2010	12,038	10,441	881	23,360	0.1%
2011	12,048	10,456	880	23,384	0.1%
2012	12,092	10,464	877	23,433	0.2%
2013	12,091	10,475	875	23,441	0.0%
2014	12,098	10,486	874	23,458	0.1%
2015	12,238	10,614	881	23,733	1.2%
2016	12,355	10,745	889	23,989	1.1%
2017	12,479	10,853	897	24,229	1.0%
2018	12,628	10,978	907	24,513	1.2%
2019	12,771	11,104	914	24,789	1.1%
2020	12,973	11,229	923	25,125	1.4%
2021	13,178	11,355	932	25,465	1.4%
2022	13,387	11,482	939	25,808	1.3%
2023	13,600	11,610	948	26,158	1.4%
2024	13,816	11,739	957	26,512	1.4%
2025	14,035	11,870	965	26,870	1.4%

Source: Reference 8.2-1, Volume II, Chapter 2, Table 12

Table 8.2-9 Total Projected Electric Savings Due to Energy Efficiency(GWh)

	2007	2015	2025
Energy Efficiency Programming	611	8,382	14,948
Load Management (AC-Cycling)	18	35	48
Building Code	46	477	938
Appliance Standards	402	1,385	2,771
TOTAL	**1077**	**10,279**	**18,705**

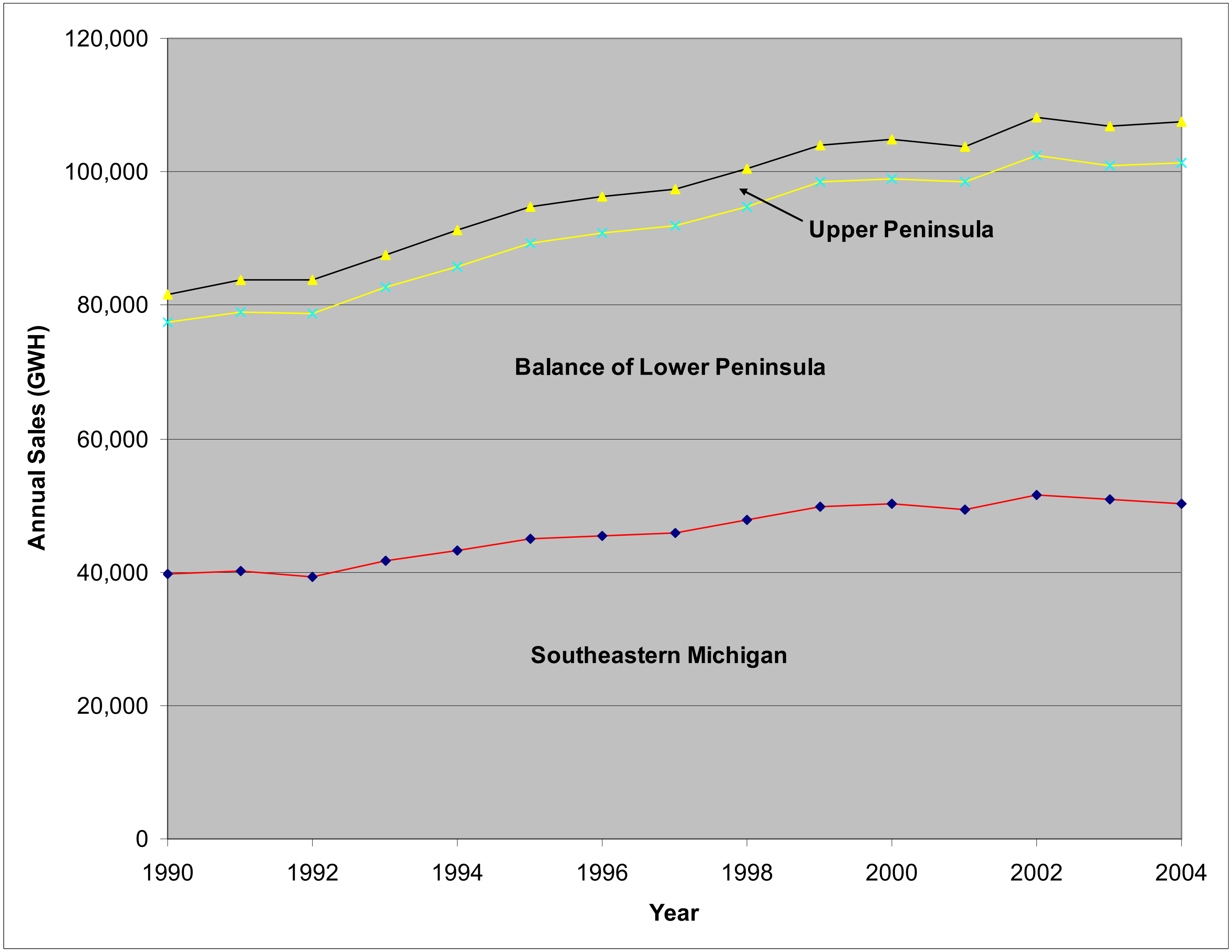
Source: Reference 8.2-1, Volume II, Chapter 3, Table 4

Table 8.2-10 Total Projected Peak Electric Demand Reduction Due to Energy Efficiency(MW)

	2007	2015	2025
Energy Efficiency Programming	85	1,205	2,115
Load Management (AC-Cycling)	294	569	764
Building Code	9	99	195
Appliance Standards	9	266	531
TOTAL	**397**	**2,139**	**3,625**

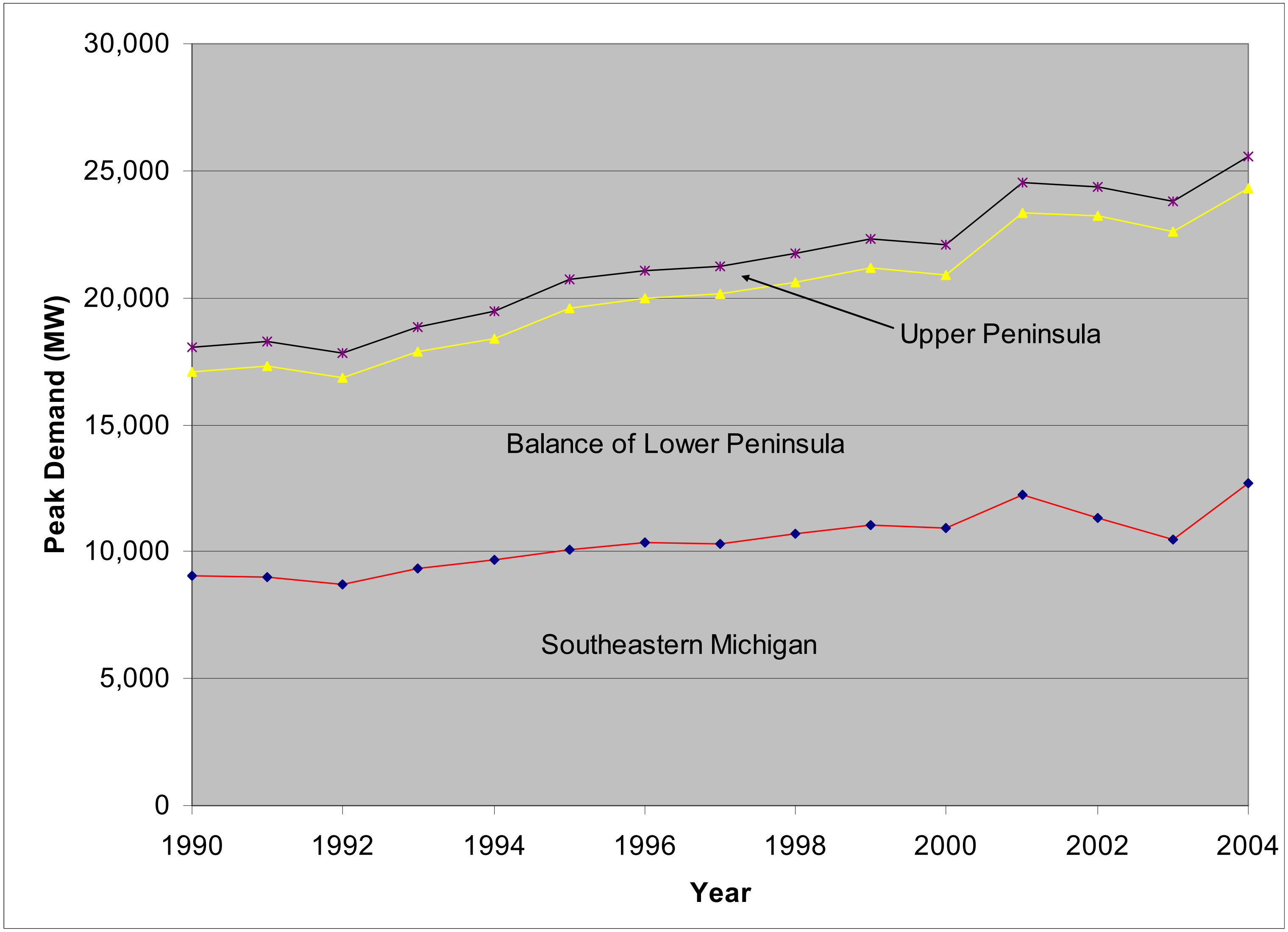
Source: Reference 8.2-1, Volume II, Chapter 3, Table 5

Figure 8.2-1 Annual Electric Sales (1990 – 2004)



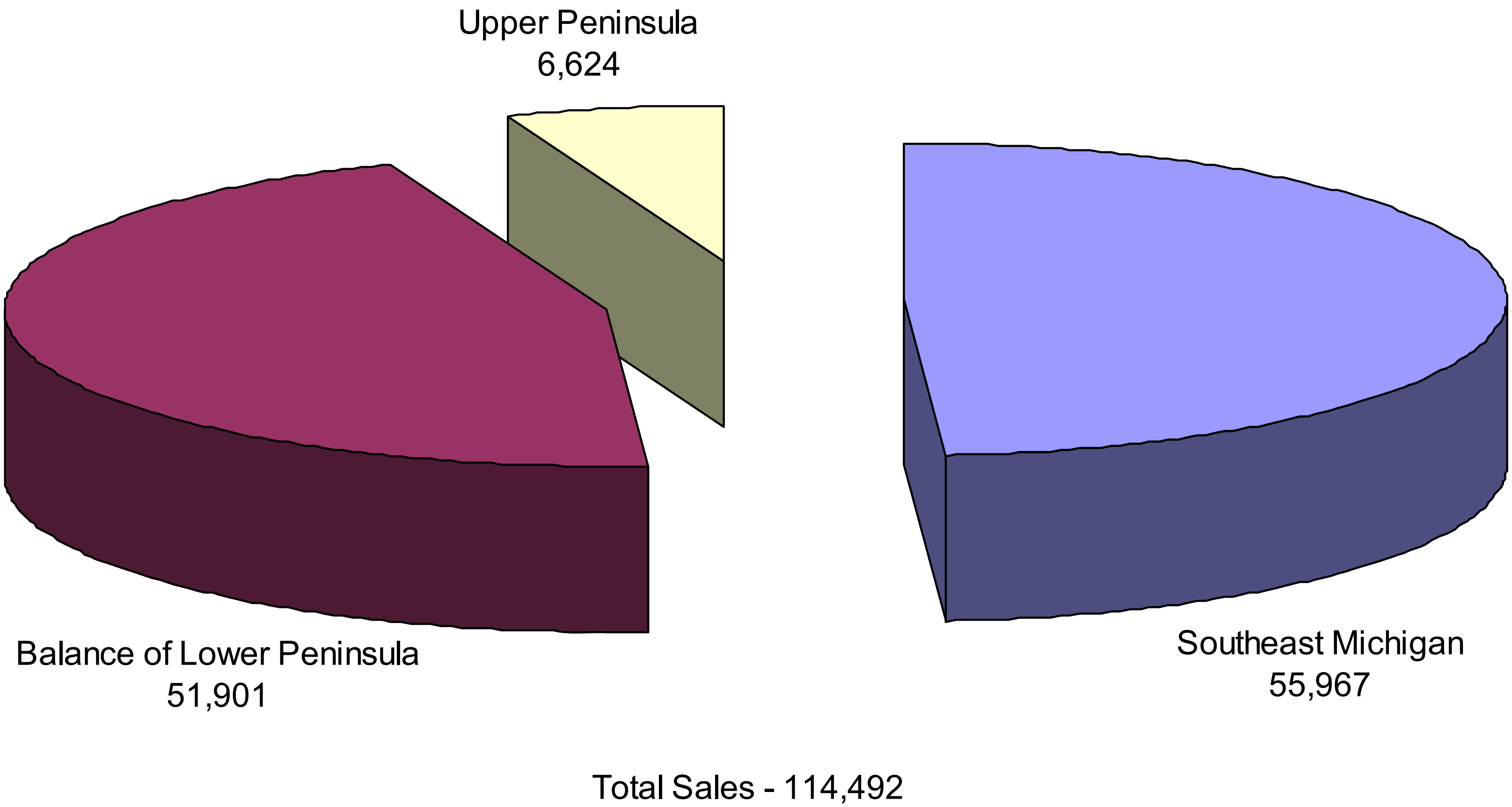
Source: Reference 8.2-1, Volume II, Chapter 2, Figure 6

Figure 8.2-2 Peak Demand (1990 – 2004)



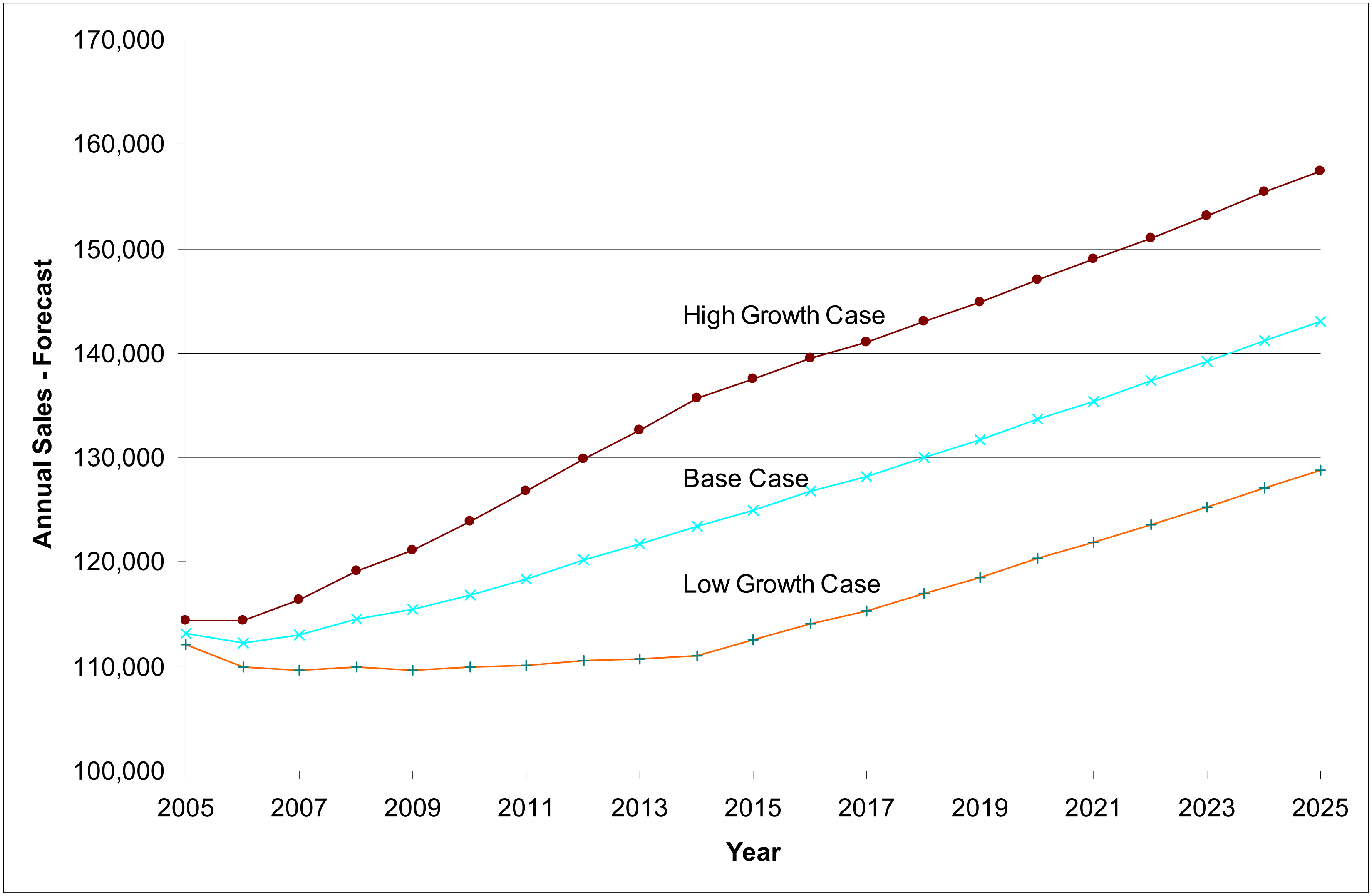
Source: Reference 8.2-1, Volume II, Chapter 2, Figure 7

Figure 8.2-3 2008 Projection of Energy Sales by Region – Base Case (Gigawatt-hours)



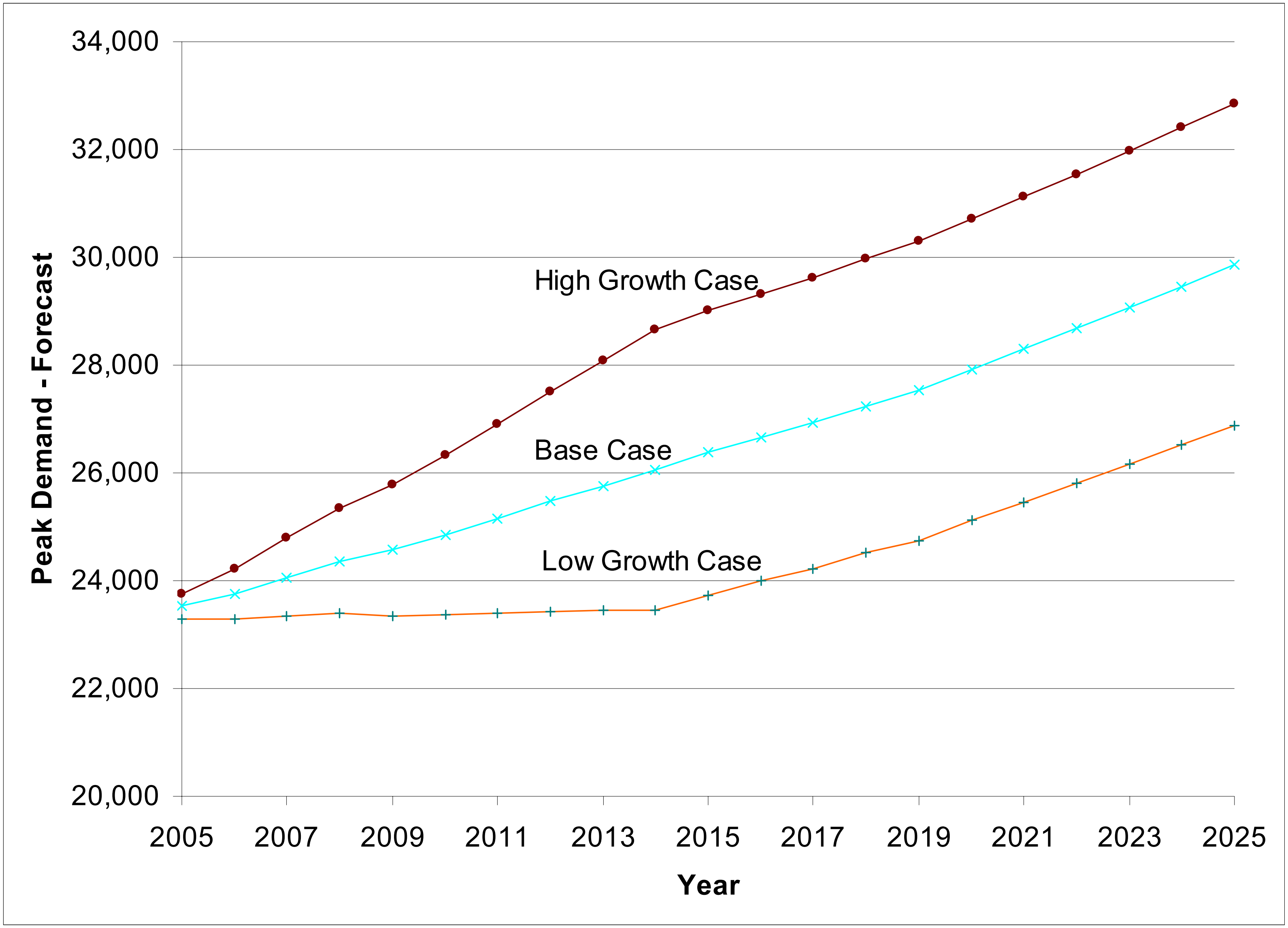
Source: Reference 8.2-1, Volume II, Chapter 2, Figure 5

Figure 8.2-4 Annual Sales Forecast



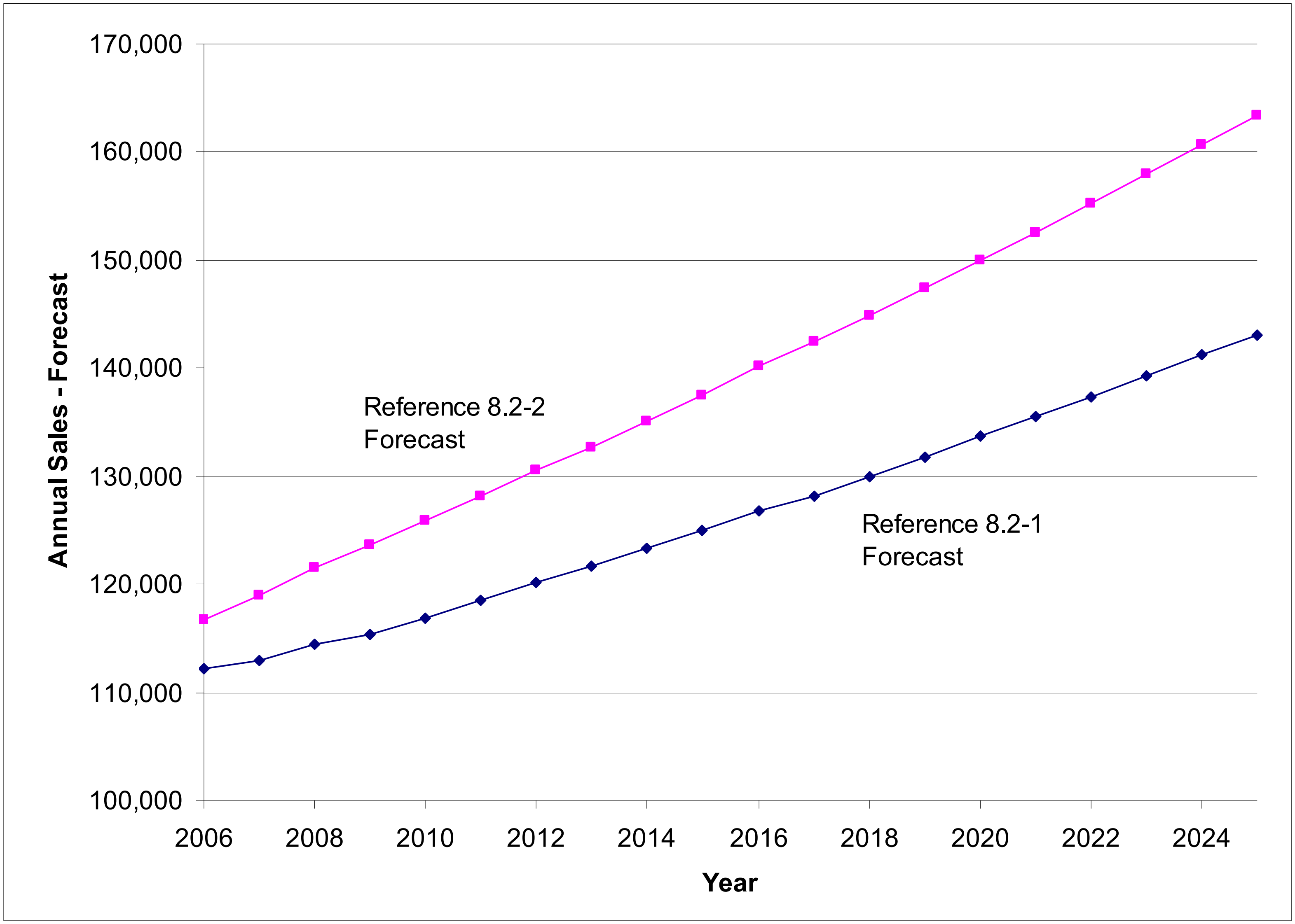
Source: Reference 8.2-1, Volume II, Chapter 2, Figure 6

Figure 8.2-5 Peak Demand Forecast



Source: Reference 8.2-1, Volume II, Chapter 2, Figure 7

Figure 8.2-6 Comparison of Electrical Sales Forecasts



Source: Reference 8.2-1, Volume II, Chapter 2, Figure 8

8.3 Power Supply

This section evaluates the existing and planned generating capability plus the present and planned purchases and sales of power and energy. This section includes consideration of the type and function of the region's power plants, proposed additions, retirements, redesignations, deratings, or upratings of the region's plants.

The information that is presented in this section is a summary of the information provided in Michigan's 21st Century Electric Energy Plan (Reference 8.3-1). The Michigan 21st Century Electric Energy Plan satisfies the NRC's evaluation criteria of being (1) systematic; (2) comprehensive; (3) subject to confirmation; and (4) responsive to forecast uncertainty. The planning period for the Michigan 21st Century Electric Energy Plan extends through 2025, or well beyond the planned date of commercial operation for the proposed project. The basis for this conclusion is discussed in Subsection 8.1.5.

The following definitions apply to the terms used in this section:

- Base Load – The baseload requirement is the firm load level that is expected to be exceeded for a majority of all hours per year. Generation units that serve this role are dispatched at or near maximum capacity on-peak when available.
- Intermediate – Generation units that serve the time-varying load shape levels in the intermediate range above the baseload supply requirement throughout the year.
- Peaking – Generation units that serve the peaking load levels that are above the baseload and intermediate load following requirements during the peak period.
- Firm – Sales of power that cannot be interrupted except in certain circumstances. A utility plans to have adequate resources to serve these customers.
- Nonfirm – Sales to customers that usually receive a lower rate in exchange for power that can be interrupted. A utility does not need to plan for adequate uninterrupted power to meet these customers' needs.

8.3.1 Existing and Forecasted Generating Capacity

8.3.1.1 Existing Generating Capability

As discussed in the 21st Century Plan , Michigan relies on coal and nuclear fueled baseload generation units for approximately 83 percent of its annual electricity production, natural gas for approximately 13 percent of its annual production, and from hydro and other sources for approximately 4 percent of its generation. Table 8.3-1 through Table 8.3-3 summarize the currently operational generation units, by region in Michigan. Table 8.3-1 through Table 8.3-3 exclude American Electric Power's (AEP) Cook nuclear units in Southwestern Lower Michigan, which collectively represent approximately 2000 MW of generating capacity. The Cook units are excluded as they are committed to the PJM system and are not dispatched or available to the Midwest ISO for the purposes of meeting non-AEP Lower Peninsula power needs.

The inventory of existing generating facilities was cataloged as part of the development of the plan. This inventory identification was reviewed by Consumers Energy, Detroit Edison, Wolverine Power Supply Cooperative, and Lansing Board of Water and Light. Participants in the development of the inventory listing concurred that the data was accurate and appropriate for use in the modeling. Table 8.3-4 through Table 8.3-7 provide a detailed list of existing generating resources greater than 100 MW within the State of Michigan. The existing generation resources consist of natural gas combined cycle and combustion turbine units; hydroelectric run-of-river, storage, and pumped storage units; coal, natural gas, and oil steam turbines; and nuclear. The information in Table 8.3-4 through Table 8.3-7 provides a listing of generation resources by region, identifying generator type, generator name and annual maximum capacity in MW. Figure 8.3-1 through Figure 8.3-4 summarize the existing generation by generator type and by fuel.

8.3.1.2 Forecasted Generating Capability

Forecasted generating capability is a function of new (planned and proposed) generating plants and the retirement schedule for existing generating plants. This subsection addresses new generating plants. The retirement schedule for existing generating plants is discussed in Subsection 8.3.3. As discussed in Subsection 8.3.3, the total electrical generation capability that is forecasted to retire is 3755 MW.

One of Midwest ISOs primary roles is the oversight of the reliability planning process. Midwest ISO manages incremental generation capacity development through the Generation Interconnection Request Queue. Developers wishing to provide new incremental generation must file an interconnection request and enter into Midwest ISOs queue-based, 3-study interconnection process, which provides developers the flexibility to consider and explore their respective generation interconnection business opportunities. While a developer can withdraw a project from the Generation Interconnection Request Queue at any point, the process is structured such that each step imposes its own increasing financial obligations on the developer. It is recognized that not all projects in the Generation Interconnection Queue are likely to be built, but the Queue provides an authoritative source for future generation investment trends in the Midwest ISO Regional Transmission Operator (RTO).

The Midwest ISO transmission system has been divided into study regions for the purposes of managing the processing of the queue. Generators in separate regions will be considered for simultaneous processing. Where there is a question of system impacts between Generators in separate study regions, the overall queue position will prevail for determination of study order, system impacts, and determination of any associated upgrades. The study regions are reviewed periodically and adjusted as necessary. (Reference 8.3-3)

Table 8.3-8 lists the individual generation interconnection requests for projects located in the Michigan area of the Midwest ISO RTO, as of June 11, 2008 (Reference 8.3-4). Table 8.3-8 provides the Midwest ISO Queue number, the Michigan County where the new unit is operating / proposed, the maximum MW output of the unit, in-service date, and fuel type. Analysis of the individual generation interconnection requests in the overall Midwest ISO Queue reveals 28 active generating interconnection requests in the State of Michigan totaling 7015 MW, maximum summer output. Table 8.3-9 provides an overall summary of the active interconnection requests in the State of Michigan by fuel type. As shown, the dominant generation by fuel type are wind (42 percent), coal (32 percent), and nuclear (22 percent).

8.3.2 Purchases and Sales

The development of the 21st Century Plan included participation from a Transmission and Distribution Workgroup. The Transmission and Distribution Workgroup was charged with estimating the transmission import capability into Michigan. The Workgroup's specific responsibilities included:

1. Estimating the transmission import capability into Michigan in 2009 with no transmission system modifications beyond those planned or proposed in the 2005 Midwest ISO Transmission Expansion Plan (MTEP).
2. Identifying transmission system upgrades that may be available to increase transmission transfer capability within Michigan and into Michigan.
3. Reviewing issues that may have an impact on the State's ability to utilize or expand its transmission system.

Figure 8.3-5 represents the results of the Transmission and Distribution Workgroup's estimation of import capability. Interface capability between the Upper Peninsula and METC was assumed to be 50 MW at the Straights of Mackinaw. Following the completion schedule planned for the Upper Peninsula northern umbrella project (NUP) transmission upgrades, American Transmission Company (ATC) interface capability with external markets is expected to increase to 224 MW in 2005, 300 MW in 2006, 325 MW in 2008 and 525 MW in 2010.

For the purposes of Michigan integrated resource modeling, external capacity selling into or purchasing from the Michigan market was excluded. The external market was utilized to represent only Nonfirm economy energy interchanges.

Two transmission scenarios were modeled, one representing a Low Import case and the other an Expanded Transmission case. The Low Import case assumed 1500 MW of sales utilizing Michigan transmission to transfer power from Midwest ISO to Ontario Hydro. Figure 8.3-6 represents transfer capabilities modeled for the Low Import case.

The Expanded Transmission case assumed an additional 2500 MW of transfer capability into ITC*Transmission* with the cost assumed to be shared by the State of Michigan and transmission users in the rest of the Midwest ISO footprint. Figure 8.3-7 represents the impact of this 2500 MW expansion transfer capability.

The estimated transfer capabilities into Michigan's Lower Peninsula for the Base Case, the Expanded Transmission case and the Low Import case are summarized in Table 8.3-10.

One major change in the assumptions from the work performed in the CNF study report was made in the development of the 21st Century Plan. The CNF study report, Base Case, assumed that 3000 MW of on-peak transfer capability was available into Michigan in 2009. While this estimate has not changed, approximately 800 MW were reserved for Firm transmission service by parties outside of Michigan. Therefore, the amount of transfer capability available for reliability designated for Michigan is not more than 2200 MW.

There are two factors that can reduce allowable transfer capabilities to lower levels. One is Transmission Reliability Margin (TRM), which is used by the Midwest ISO as a measure of uncertainty in quantities like transmission equipment ratings, or parallel flows from remote utilities. A second reduction is due to coordination with the neighboring utilities AEP and ComEd. The Midwest ISO-PJM Coordination Agreement requires that Midwest ISO allocate some capacity to PJM member utilities.

For economy energy purposes, 3000 MW are assumed to be available. Due to Firm reservations on the Michigan transmission system however, the amount of on-peak transmission that is available for Michigan market participants to support reliability needs was reduced to 2200 MW. In addition to these Firm reservations, Michigan remains subject to loop flow that can further restrain the amount of transmission into Michigan.

As part of the continuing evaluation of transmission system capabilities, different options for system upgrades were identified. These options were divided into two different classes (TIER I and TIER II). TIER I upgrades represent modifications to the existing system that could be made primarily using existing right-of-ways. These types of upgrades include adding transformers and reconfiguring/upgrading lines, in order to get more throughput from the existing system. TIER II upgrades initially consisted of three possible major, new transmission projects running from the Detroit area to southwest Michigan. These competing possible projects prompted the Midwest ISO to commence the Michigan Exploratory Study as part of the Midwest ISO Transmission Expansion Plan (MTEP 2006) process. The options being considered are a 2500 MW direct current line or an alternative extension of the 765 kV system from southwestern Michigan to northwest Detroit. A substantial portion of the proposed line's benefit is relieving reliability issues in southeastern Michigan.

In November 2006, ITC*Transmission* and AEP announced plans to jointly study a 765 kV loop through Michigan's Lower Peninsula that would potentially be in both ITC*Transmission*'s and METC's service territories and link to AEP's existing 765 kV transmission infrastructure. The draft MTEP 2006 report includes this 765 kV loop as a proposed project with an in-service date of 2016.

New investments in transmission alone do not guarantee the additional capacity is reserved for the needs of Michigan. Commitments for transmission usage are determined by energy market rules of the Midwest ISO system operation tariff and may be sold to third parties on a first come – first served basis.

8.3.3 **Potential Retirements**

Retirements of operating baseload units reduce the available capacity of electrical generation. As of January 2007, Michigan's baseload generating plants are an average of more than 48 years old (Reference 8.3-1).

The modeling assessments in the plan consider unit retirements. The following assumptions were used for unit retirements:

- Coal units will retire after 65 years.
- Nuclear units will retire after 60 years.
- Combined cycle units will retire after 40 years.
- Combustion turbine units will retire after 30 years.
- No existing combustion turbines will be retired during the study. It is assumed that all existing combustion turbines will be replaced in kind.

Based on these assumptions, the detailed schedule of unit retirements is shown in Table 8.3-11. Table 8.3-12 summarizes the aggregate capacity retirements each year, through the course of the study horizon. At the end of the current study period, the total electrical generation capacity that is forecasted to retire is 3755 MW.

8.3.4 **References**

8.3-1 Lark, J. Peter, Chairman Michigan Public Service Commission, “Michigan’s 21st Century Electric Energy Plan,” Submitted to Honorable Jennifer M. Granholm, Governor of Michigan, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm, accessed 18 January 2008.

8.3-2 Stojic, George, Director Operations & Wholesale Markets Division, to Michigan Public Service Commission, Chairman J. Peter lark, Commissioner Laura Chappelle, and Commissioner Monica Martinez, “Final Staff Report of the Capacity Need Forum,” (3 January 2006), http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/, accessed 18 January 2008.

8.3-3 Midwest ISO Interconnection, http://www.midwestiso.org/page/Generator+Interconnection, accessed 11 June 2008.

8.3-4 Midwest ISO Generation Interconnection Request Queue, http://www.midwestmarket.org/page/Generator+Interconnection+Queue, accessed 11 June 2008.

Table 8.3-1 Michigan Electrical Generating Unit Inventory, Region: Southeast Michigan

Plant Type	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Average Unit (MW)	Number of Units
Ownership: Investor Owned Utility						
Nuclear	1,110	1,125	1,110	1,110	1,110	1
Steam Generator	8,248	8,275	775	83	317	26
Combined Cycle/GT	969	1,188	82	11	31	31
Internal Combustion	152	152	3	0.8	2.5	61
Subtotal	10,479	10,740	1,970	[1,204.8]	1,460.5	119
Ownership: Municipality / Cooperative / Public Authority						
Steam Generator	470	472	118	20	59	8
Combined Cycle/GT	25	30	25	25	25	1
Internal Combustion	39	40	3	0.4	1.1	36
Subtotal	534	542	146	45.4	85.1	45
Ownership: Non-Utility						
Steam Generator	326	338	199	1	47	7
Combined Cycle/GT	1,502	1,515	570	2	65	23
Hydro	5	6	2	0.5	1	5
Internal Combustion	76	77	5	0.1	1	76
Subtotal	1,909	1,936	776	3.6	114	111
Region Total	**12,922**	**13,218**	**2,892**	**1,253.8**	**1,659.6**	**275**
Michigan Total	**[27,991]**	**28,535**	**5,843.6**	**2,335.8**	**3,251.9**	**859**
Region % of Total	**46.2%**	**46.3%**	**49.5%**	**53.7%**	**51%**	**32%**

Values in brackets represent editorial corrections to the values given in Reference 8.3-1.
Source: Reference 8.3-1, Volume II, Chapter 2, Table 1

Table 8.3-2 Michigan Electrical Generating Unit Inventory, Region: Balance of Lower Peninsula

Plant Type	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Average Unit (MW)	Number of Units
Ownership: Investor Owned Utility						
Nuclear	767	811	760	760	760	1
Steam Generator	3,932	3,937	737	52	281	14
Combined Cycle/GT	358	438	30	2	17	21
Hydro	95	113	10	0.2	1.4	69
Pumped Storage	1,872	1,872	159	153	156	12
Subtotal	[7,024]	7,171	1,696	967.2	1,215.4	117
Ownership: Municipality / Cooperative / Public Authority						
Steam Generator	840	860	158	8	40	21
Combined Cycle/GT	428	459	73	11	29	15
Hydro	8	9	1	0.1	0.4	23
Internal Combustion	171	171	8	0.1	2.2	77
Wind	1	1	0.6	0.6	0.6	1
Subtotal	1,448	1,500	240.6	19.8	72.2	137
Ownership: Non-Utility						
Steam Generator	355	374	30	2	14	26
Combined Cycle/GT	4,896	4,909	671	0.8	119	41
Hydro	22	22	3	0.1	0.6	38
Internal Combustion	241	241	59	0.5	5	49
Wind	2	2	0.9	0.9	0.9	2
Subtotal	5,516	5,548	763.9	4.3	139.5	156
Region Total	**[13,988]**	**14,219**	**2,700.5**	**991.3**	**1,427.1**	**410**
Michigan Total	**[27,991]**	**28,535**	**5,843.6**	**2,335.8**	**3,251.9**	**859**
Region % of Total	**50%**	**49.8%**	**46.2%**	**42.4%**	**43.9%**	**47.7%**

Values in brackets represent editorial corrections to the values given in Reference 8.3-1.
Source: Reference 8.3-1, Volume II, Chapter 2, Table 1

Table 8.3-3 Michigan Electrical Generating Unit Inventory, Region: Upper Peninsula

Plant Type	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Average Unit (MW)	Number of Units
Ownership: Investor Owned Utility						
Steam Generator	613	613	90	25	68	9
[Combined Cycle/GT]	24	28	24	24	24	1
[Hydro]	139	142	8	0.1	1.1	121
Internal Combustion	5	5	3	2	2	2
Subtotal	781	788	125	51.1	95.1	133
Ownership: Municipality / Cooperative / Public Authority						
Steam Generator	82	82	44	13	21	4
Combined Cycle/GT	23	24	23	23	23	1
Hydro	10	10	1.6	0.3	1.0	10
Internal Combustion	17	17	2.5	0.5	1.7	10
Subtotal	132	133	71.1	36.8	46.7	25
Ownership: Non-Utility						
Steam Generator	146	155	50	2.4	21	7
Hydro	22	22	5	0.4	2.4	9
Subtotal	168	177	55	2.8	23.4	16
Region Total	**1,081**	**1,098**	**251.1**	**90.7**	**165.2**	**174**
Michigan Total	**[27,991]**	**28,535**	**5,843.6**	**2,335.8**	**3,251.9**	**859**
Region % of Total	**3.9%**	**3.9%**	**4.3%**	**3.9%**	**5.1%**	**20.3%**

Values in brackets represent editorial corrections to the values given in Reference 8.3-1.
Source: Reference 8.3-1, Volume II, Chapter 2, Table 1

Table 8.3-4 ITC*Transmission* Region, Existing Generation Resources (Greater than 100 MW)

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Combined Cycle	Dearborn Industrial Generation LLC:CC1	760
Combustion Turbine Gas	MPPA: Belle River	234
Nuclear	Fermi: 2	1,111
Steam Turbine Coal	Belle River: ST1	509
Steam Turbine Coal	Belle River: ST2	517
Steam Turbine Coal	Harbor Beach: 1	103
Steam Turbine Coal	Monroe: 1	770
Steam Turbine Coal	Monroe: 2	785
Steam Turbine Coal	Monroe: 3	785
Steam Turbine Coal	Monroe: 4	775
Steam Turbine Coal	River Rouge: 2	238
Steam Turbine Coal	River Rouge: 3	272
Steam Turbine Coal	St. Clair: 1	153
Steam Turbine Coal	St. Clair: 2	162
Steam Turbine Coal	St. Clair: 3	171
Steam Turbine Coal	St. Clair: 4	158
Steam Turbine Coal	St. Clair: 6	321
Steam Turbine Coal	St. Clair: 7	450
Steam Turbine Coal	Trenton Channel: 8	210
Steam Turbine Coal	Trenton Channel: 9	520
Steam Turbine Gas	Conners Creek: 16	215
Steam Turbine Gas	River Rouge: 1	234
Steam Turbine Oil	Greenwood: 1	785

Source: Reference 8.3-1, Volume II, Chapter 1, Table 20

Table 8.3-5 METC Region, Existing Generation Resources (Greater than 100 MW)

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Combined Cycle	Covert: CC3	384
Combined Cycle	Covert: CC4	384
Combined Cycle	Covert: CC5	384
Combined Cycle	Jackson: CCA	280
Combined Cycle	Jackson: CCB	280
Combined Cycle	Michigan Power L.P.: CC	123
Combined Cycle	Midland Cogeneration Venture (MCV): CC	1,240
Combined Cycle	Zeeland (MIR): CC1	532
Combustion Turbine Gas	Renaissance Power Project: GT1	171
Combustion Turbine Gas	Renaissance Power Project: GT2	171
Combustion Turbine Gas	Renaissance Power Project: GT3	171
Combustion Turbine Gas	Renaissance Power Project: GT4	171
Combustion Turbine Gas	Zeeland (MIR): GT1	149
Combustion Turbine Gas	Zeeland (MIR): GT2	149
Nuclear	Palisades (CEC): 1	803
Pumped Storage Hydro	Ludington: PSOP6	1,872
Steam Turbine Coal	Campbell (CEC): 1	260
Steam Turbine Coal	Campbell (CEC): 2	360
Steam Turbine Coal	Campbell (CEC): 3	820
Steam Turbine Coal	Cobb: 4	160
Steam Turbine Coal	Cobb: 5	160
Steam Turbine Coal	Karn: 1	255
Steam Turbine Coal	Karn: 2	260
Steam Turbine Coal	Weadock: 7	155
Steam Turbine Coal	Weadock: 8	155
Steam Turbine Coal	Whiting (CEC): 1	102
Steam Turbine Coal	Whiting (CEC): 2	102
Steam Turbine Coal	Whiting (CEC): 3	124
Steam Turbine Gas	Karn: 4	638
Steam Turbine Oil	Karn: 3	638

Source: Reference 8.3-1, Volume II, Chapter 1, Table 21

Table 8.3-6 Wolverine Power Supply Cooperative, Existing Generation Resources (Greater than 100 MW)

Generator Type	Generator Name	Annual Maximum Capacity (MW)
None		

Source: Reference 8.3-1, Volume II, Chapter 1, Table 22

Table 8.3-7 Lansing Board of Water & Light, Existing Generation Resources (Greater than 100 MW)

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Steam Turbine Coal	Erickson: 1	158.5

Source: Reference 8.3-1, Volume II, Chapter 1, Table 23

Table 8.3-8 Midwest ISO Interconnection Request Queue as of June 11, 2008

Project Number	Queue Number	County	Max Summer Output (MW)	Max Winter Output (MW)	In-Service Date	Fuel Type
G513	38457-02	Oceana	100	100	10/1/2006	Wind
G687	39001-01	Midland	750	750	12/1/2010	Coal
G742	39129-02	Missaukee	120	120	12/31/2010	Wind
G743	39129-03	Missaukee	45	45	12/31/2010	Wind
G750	39140-02	Marquette	200	200	9/30/2009	Wind
G755	39141-02	Osceola	50	50	6/1/2009	Wind
G766	39160-02	Hillsdale	300	300	8/30/2010	Wind
G774	39168-02	Mason	70	70	6/1/2010	Wind
G799	39216-02	Houghton	120	120	11/30/2009	Wind
G809	39245-05	Midland	193		12/31/2008	Gas
G814	39262-02	Kalkaska	36	36	3/31/2010	Biomass
G820	39279-04	Presque Isle	600	600	2/28/2011	Coal
G854	39335-01	Mason	150	150	12/31/2011	Wind
G867	39350-02	Monroe	1,563	1,563	3/31/2017	Nuclear
G872	39357-03	Bay	863	875	3/1/2015	Coal
G889	39373-01	Huron	59	59	12/31/2008	Wind
G905	39388-02	Gratiot & Saginaw	200	200	6/30/2010	Wind
G918	39413-01	Gratiot	120	120	7/1/2010	Wind
G919	39413-02	Charlevoix	120	120	12/15/2010	Wind
G934	39430-01	Gratiot	300	300	10/1/2010	Wind
G937	39436-01	Delta	200	200	12/31/2010	Wind
G938	39436-02	Newaygo	0	0	12/15/2008	Hydro
G943	39442-04	Kent & Ottawa	150	150	12/1/2011	Wind
G944	39442-05	Kent & Ottawa	150	150	12/1/2011	Wind
G958	39475-01	Kent & Ottawa	120	120	12/31/2010	Wind
G997	39545-01	Huron	200	200	12/31/2012	Wind
H030	39588-01	Tuscola	200	200	12/1/2012	Wind
H034	39589-02	Kalkaska	36	36	6/1/2011	Biomass
		Total	**7,015**	**6,834**		

Source: Reference 8.3-4

Table 8.3-9 Summary of Active Generator Interconnection Requests In the State of Michigan by Fuel Type (As of June 11, 2008)

Fuel Type	Max Summer Output (MW)	Percent
Biomass	72	1%
Coal	2,213	32%
Hydro	0	0%
Natural Gas	193	3%
Nuclear	1,563	22%
Wind	2,974	42%
Total	7,015	100%

Source: Reference 8.3-4

Table 8.3-10 Key Interface Capabilities

	Base Case (MW)	Expanded (MW)	Low Import (MW)
Into Michigan	3000	5500	1650
Into METC	3400	3400	1450
Into ITC *Transmission*	650	3150	200
METC/ITC *Transmission*	2850	2850	1800

Source: Reference 8.3-1, Volume II, Chapter 1, Table 7

Table 8.3-11 Modeled Unit Retirement Schedule

Plant Name	Unit #	Owner	Fuel Type	Retire Year	Capacity MW
Cobb	1	Consumers Energy	Gas	2013	68
Cobb	2	Consumers Energy	Gas	2013	61
Cobb	3	Consumers Energy	Gas	2015	52
Mistersky	5	City of Detroit	Oil	2015	39
Trenton Channel	8	Detroit Edison	Coal	2015	210
James De Young	3	Holland DPW	Coal	2016	11
Conners Creek	16	Detroit Edison	Gas	2016	215
Whiting	1	Consumers Energy	Coal	2017	102
Whiting	2	Consumers Energy	Coal	2017	102
Whiting	3	Consumers Energy	Coal	2018	124
St. Clair	1	Detroit Edison	Coal	2018	153
St. Clair	2	Detroit Edison	Coal	2018	162
Eckert	1	Lansing BWL	Coal	2019	46
St. Clair	3	Detroit Edison	Coal	2019	171
St. Clair	4	Detroit Edison	Coal	2019	158
Weadock	7	Consumers Energy	Coal	2020	155
Presque Isle [1]	1	Upper Peninsula Power	Note 2	2020	25
Cobb	4	Consumers Energy	Coal	2021	160
River Rogue	1	Detroit Edison	Gas	2021	242
Cobb	5	Consumers Energy	Coal	2022	160
Weadock	8	Consumers Energy	Coal	2022	155
River Rogue	2	Detroit Edison	Coal	2022	247
Wyandotte	5	Wyandotte	Gas	2022	22
Eckert	2	Lansing BWL	Coal	2023	47
Mistersky	6	City of Detroit	Oil	2023	47
River Rogue	3	Detroit Edison	Coal	2023	280
Escanaba	2	Escanaba Municipal	2	2023	26
Karn	1	Consumers Energy	Coal	2024	255
Karn	2	Consumers Energy	Coal	2024	260

Notes:
1. Preseque Isle Unit 1 and 2 were retired on January 1, 2007
2. Fuel type information not available in Reference 8.3-1

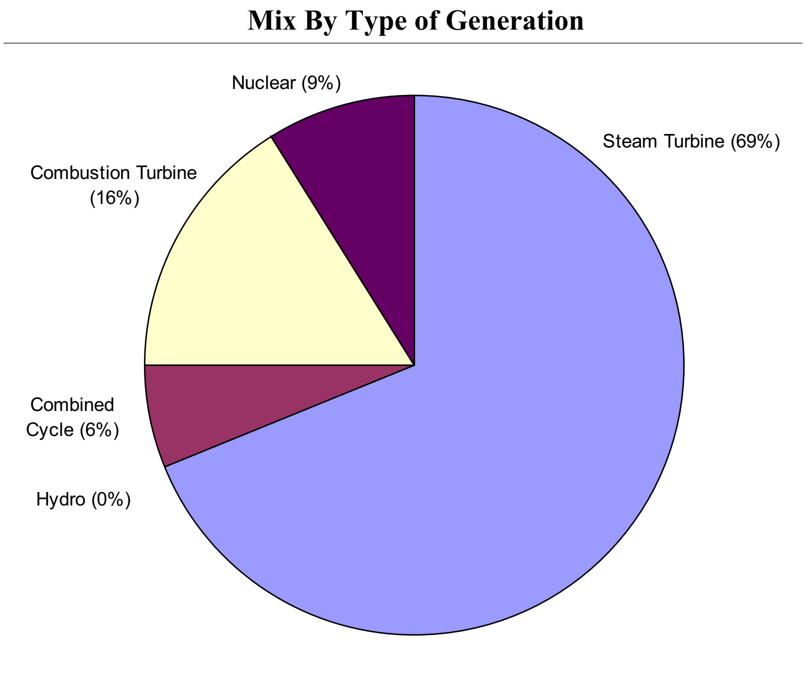
Source: Reference 8.3-1, Volume II, Chapter 1, Table 24

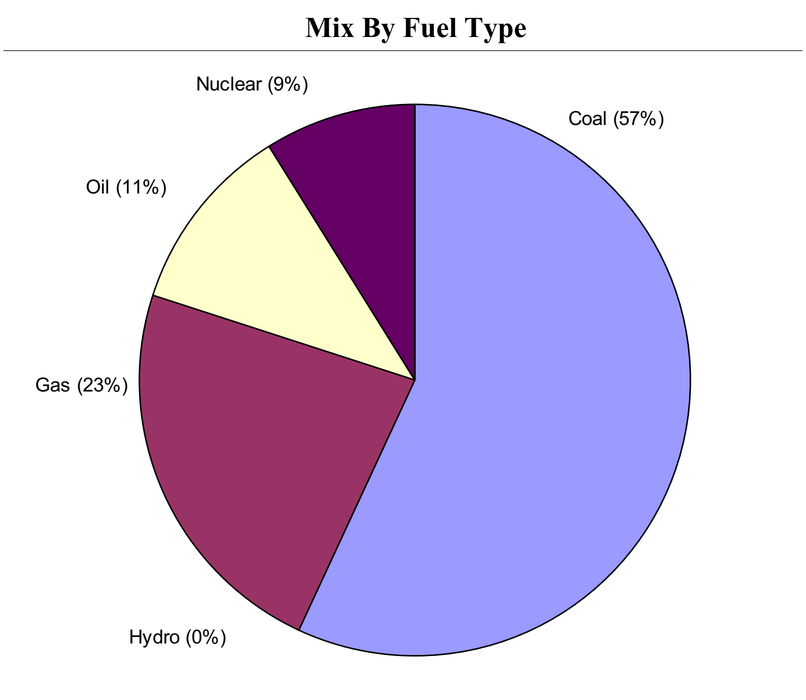
Table 8.3-12 Aggregate Unit Retirements

Year	Modeled Capacity Retired (MW)
2013	129
2014	0
2015	301
2016	226
2017	204
2018	439
2019	375
2020	180
2021	402
2022	584
2023	400
2024	515
Total	3755

Source: Reference 8.3-1, Volume II, Chapter 1, Table 1

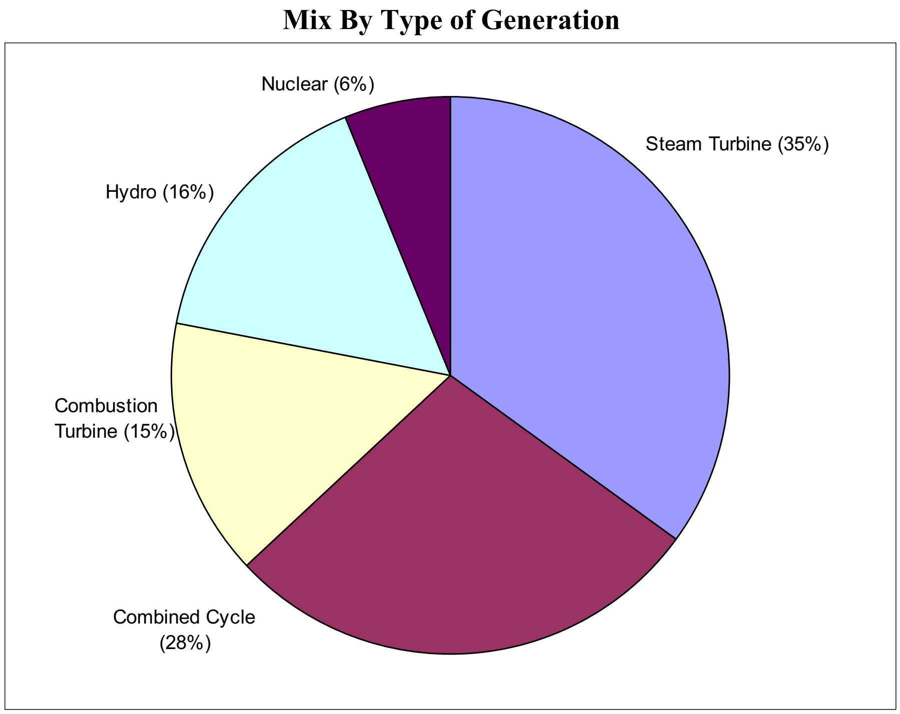
Figure 8.3-1 ITC*Transmission* Existing Capacity Mix

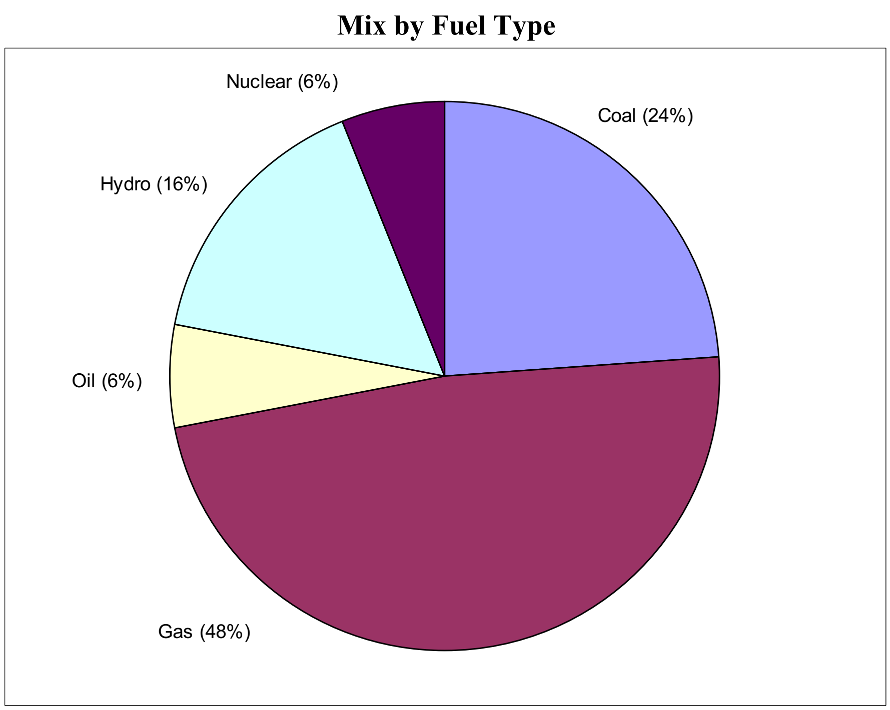




Source: Reference 8.3-1, Volume II, Chapter 1, Figure 3

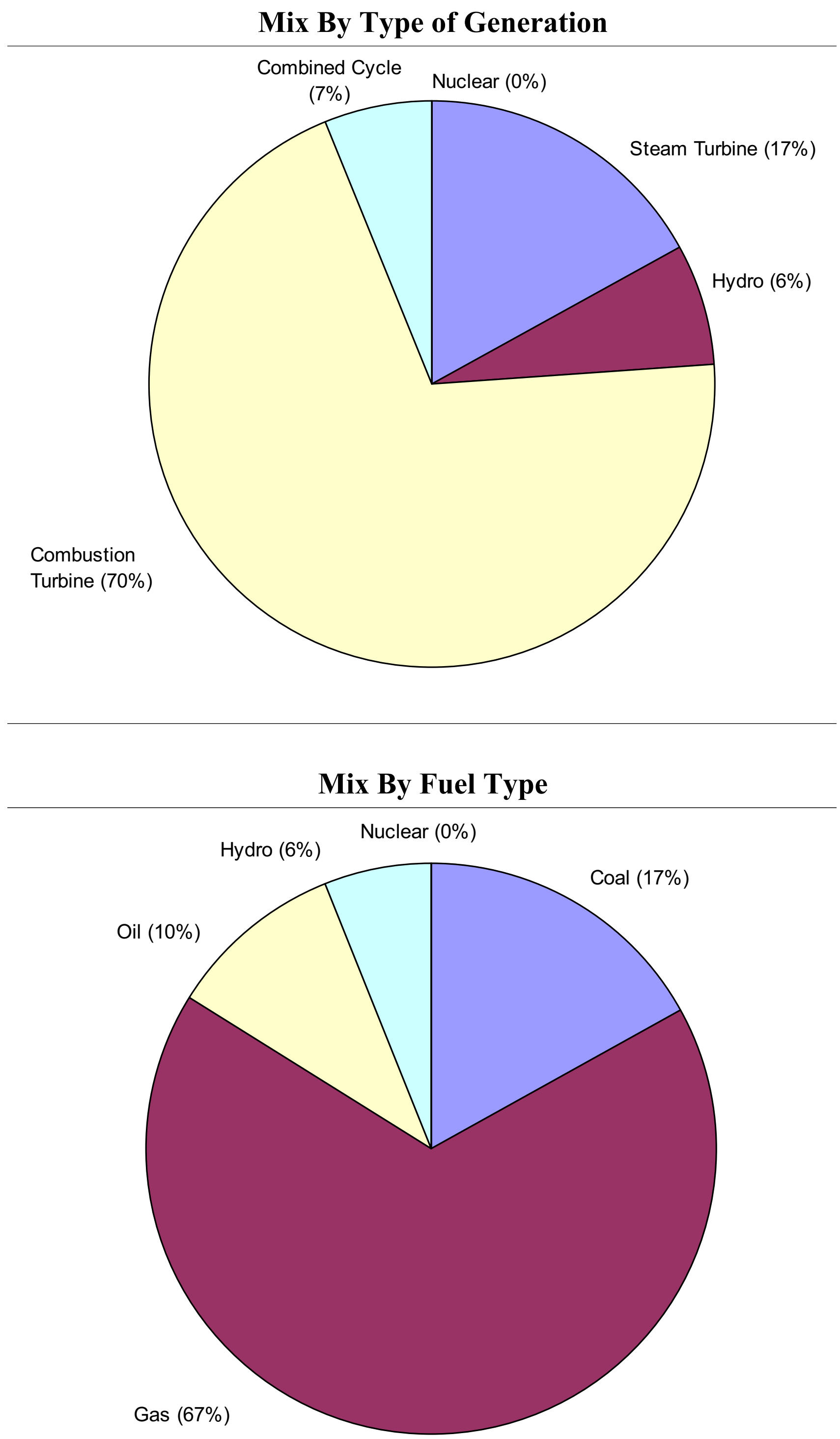
Figure 8.3-2 METC Existing Capacity Mix





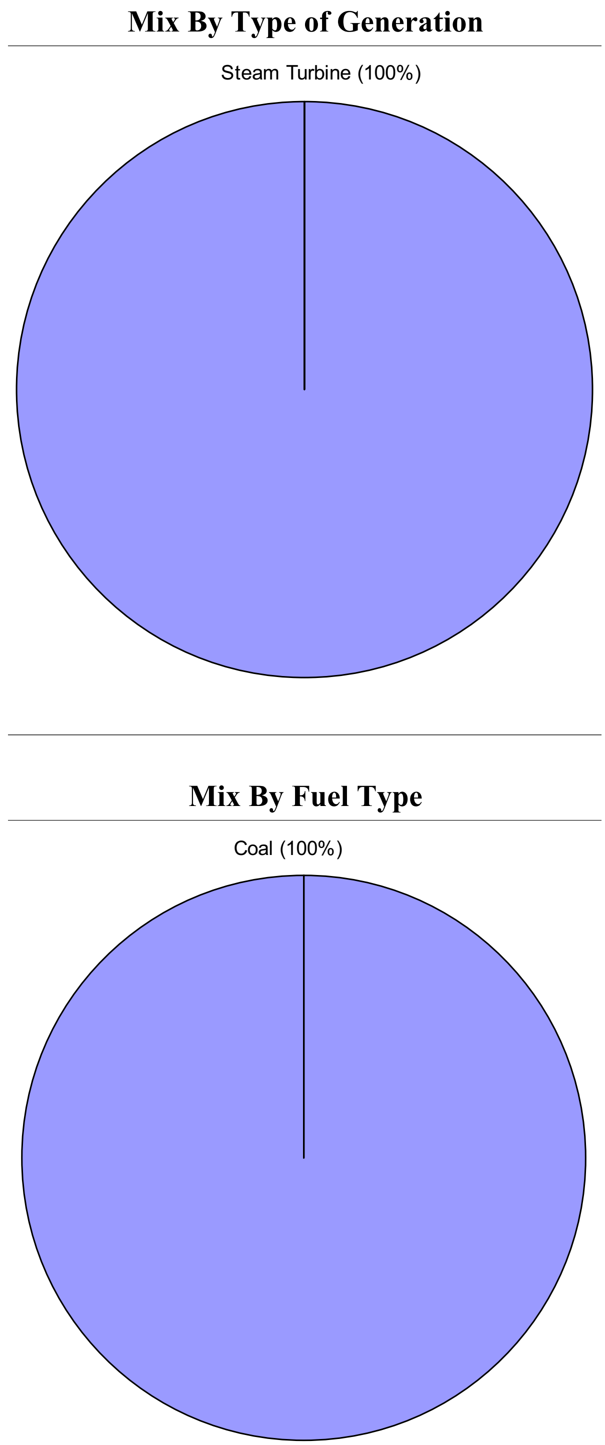
Source: Reference 8.3-1, Volume II, Chapter 1, Figure 4

Figure 8.3-3 Wolverine Existing Capacity Mix



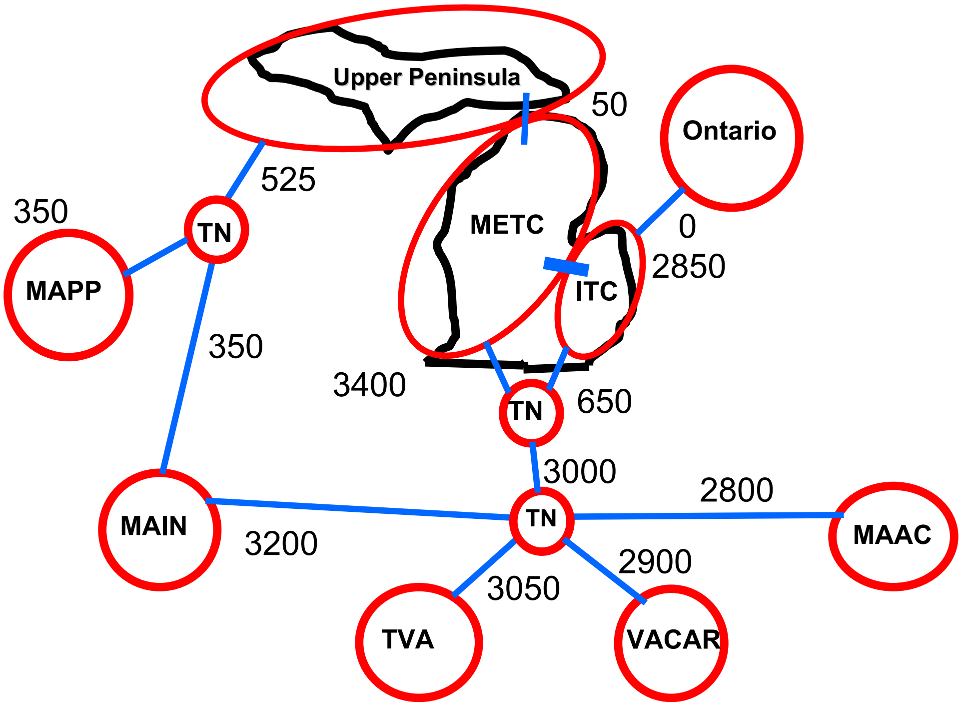
Source: Reference 8.3-1, Volume II, Chapter 1, Figure 5

Figure 8.3-4 Lansing Board of Water & Light Existing Capacity Mix



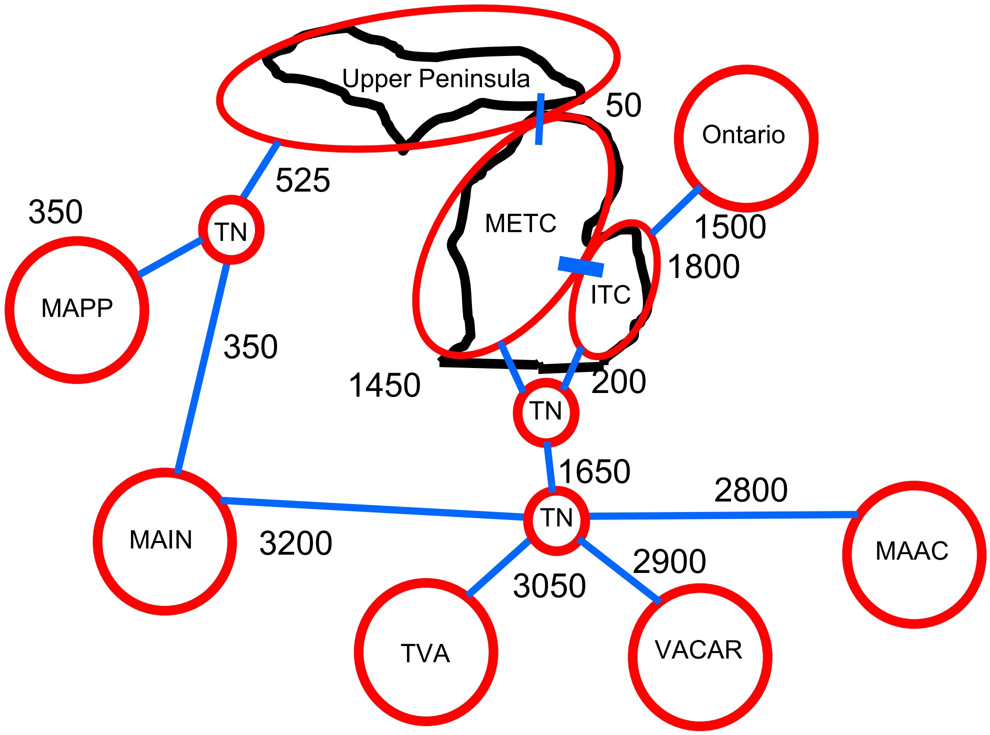
Source: Reference 8.3-1, Volume II, Chapter 2, Figure 6

Figure 8.3-5 Transmission System Interface Capability in 2009 (MW) (TN refers to Transfer Node)



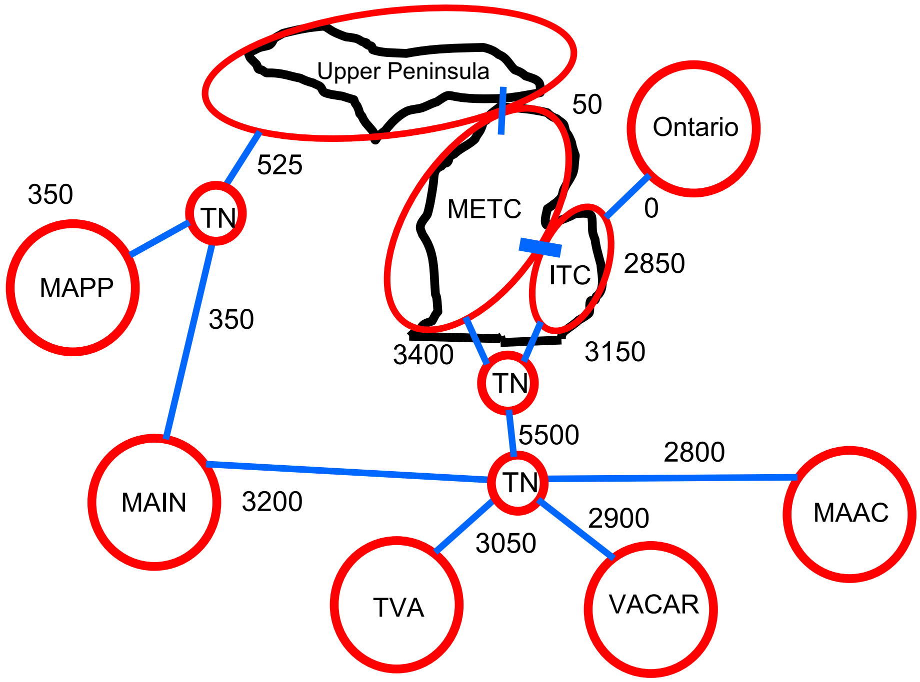
Source: Reference 8.3-1, Volume II, Chapter 1, Figure 9

Figure 8.3-6 Low Estimate of Transmission Import Capabilities in 2009 (MW)



Source: Reference 8.3-1, Volume II, Chapter 1, Figure 10

Figure 8.3-7 Expanded Estimate of Transmission Import Capabilities in 2009 (MW)



Source: Reference 8.3-1, Volume II, Chapter 1, Figure 11

8.4 Assessment of Need For Power

This section assesses the need for power within the State of Michigan. The Michigan summer peak demand and baseload demand forecasts used in this assessment are discussed in more detail in Section 8.2. Current installed capacity, planned new capacity additions, and forecasted unit retirements are discussed in more detail in Section 8.3. As discussed throughout Chapter 8, the need for power assessment is based on the State of Michigan's 21st Century Electric Energy Plan (Reference 8.4-1).

8.4.1 Need for Baseload Capacity

This section assesses the need for baseload capacity within the State of Michigan. The proposed Fermi 3 will operate as a baseload facility to help meet this need.

Michigan's current baseload generating units are on average more than 48 years old. The average age of Detroit Edison's coal-fired generation units is 44 years. As discussed in Section 8.3, modeling for the development of the Michigan 21st Century Electric Energy Plan assumes that older, less efficient units, totaling 3755 MW of capacity, will be retired by 2025.

The last new baseload plant in the State of Michigan began commercial operation more than 18 years ago. In recent years, new electric generation in Michigan has been limited to natural gas-fired facilities. Natural gas-fired units represented about 10 percent of the State's generating capacity in 1992, but now represent approximately 29 percent of that generating capacity. These units were built by independent power producers (IPPs). Many IPPs have subsequently gone through bankruptcy as the rise in natural gas prices over the past several years made even the most efficient units uneconomic to run for more than a few hours each year. Market prices driven by natural gas costs expose Michigan to volatile electricity prices.

The target reliability level is one day in 10 years loss of load probability (LOLP). As discussed in the plan, a target reliability level of one day in 10 years LOLP is the most widely acknowledged industry standard. Since electric generating plants are mechanical instruments, they are prone to fail occasionally. The reliability of each plant is based upon its planned and forced outage rates. Of particular concern is each unit's forced, or unforeseen, outage rate. This is important because if a region constructs just enough capacity to meet expected load but one of its generating plants is forced off-line, then there will be insufficient generation to meet the expected load. Therefore, a generating reserve is needed to assure that if one or more units are forced off-line, that other units are available to meet the expected load.

In determining the need for power, the plan considers the reserve margin needed to ensure reliable system operation and supply of power. The reserve margin helps ensure that there will be sufficient generating resources available to meet the load, while providing allowance for generating facilities that may be unavailable due to planned or forced outages. The reserve margin is the percent by which the generating capacity exceeds the peak demand and is defined as:

$$\text{Reserve Margin} = \frac{\text{Accredited Generating Capacity} - \text{Peak Load Responsibility}}{\text{Peak Load Responsibilty}}$$

For the purposes of the plan, the Michigan statewide reserve margin was set to 15 percent. This figure was not representative of each participant's individual planning criterion, which may differ from this statewide criterion. Resource plans were subject to this long-run 15 percent minimum target reserve margin for the Michigan system. Individually, METC and ITC*Transmission* experienced minimum reserve margins of 10 percent, phased in over the planning horizon. As discussed in the plan, for the expanded transmission sensitivity cases (below), reserve margin requirements were reduced from 15 to 12 percent. It is noted that the expanded transmission sensitivity was only included with the Central Station Generation scenario. This sensitivity was not included in other scenarios due to economic considerations.

Additionally, in the analyses modeling, no additional generating units were allowed to be added once the minimum reserve requirement had been met for any given year. Furthermore, the modeling assumed that no more than one 500 MW baseload unit would be commissioned per area (that is, METC and ITC*Transmission*) per year.

Table 8.4-1 shows the projected reserve margins if no additional resources were added to Michigan's resource portfolio. As shown in Table 8.4-1, assuming no capacity additions, the reserve margin violates the 15 percent criteria in the year 2008, and decreases every year thereafter due to projected growth of peak demand and projected unit retirements.

As part of the integrated resource plan, several scenarios and sensitivities were modeled. The scenarios, along with sensitivities run for selected scenarios, are summarized below.

- Scenarios:
  - Central Station Generation
  - Emissions (mercury and carbon dioxide restrictions)
  - Energy Efficiency
  - Renewable Energy
  - Energy Efficiency with Renewable Energy
  - Combustion Turbines Only
- Sensitivities:
  - High Load Growth
  - Low Load Growth
  - Expanded Transmission Capability
  - Low Import
  - Low Energy Efficiency Penetration

Each of the scenarios and the pertinent sensitivities run for each scenario are discussed below.

- Central Station Generation

  The Central Station Generation was performed as the Base Case. The Base Case represents a 1.21 percent demand growth rate. The following sensitivities were performed for the Base Case:

  - High Load sensitivity represented a 1.61 percent annual average demand growth rate.
  - Low Load sensitivity represented a 0.76 percent annual average demand growth rate.
  - The Expanded Transmission and Low Import sensitivities are described in Subsection 8.3.2.

- Emissions Scenario

  The Emissions Scenario was based on greater restrictions on mercury and carbon dioxide emissions than was assumed for the Base Case. The Emissions Scenario contained the following assumptions:

  1. A 15 percent increase to the mercury emissions allowance prices to reflect an additional requirement to reduce mercury emissions to 85 percent of previous levels.
  2. A nominal carbon tax on CO_2 emissions starting in 2010 at $10/ton and escalating to $30/ton in 2018.

  The following sensitivities were performed for the Emissions Scenario:

  - High Load sensitivity represented a 1.61 percent annual average demand growth rate.
  - Low Load sensitivity represented a 0.76 percent annual average demand growth rate.
  - Crediting Renewable Energy and Energy Efficiency

- Energy Efficiency Scenario

  The Energy Efficiency Scenario was focused on the effects of greater emphasis on energy efficiency investment and load management alternatives. The Energy Efficiency Scenario contained the following assumptions:

  1. Energy efficiency programs were scheduled in, and the program cost was incorporated into the present value cost calculation.
  2. Approximately 570 MW of direct load control was included.
  3. The Central Station Generation options were then re-optimized, taking into account the energy efficiency options scheduled.

  The following sensitivities were performed for the Energy Efficiency Scenario:

  - High Load sensitivity represented a 1.61 percent annual average demand growth rate.
  - Low Load sensitivity represented a 0.76 percent annual average demand growth rate.
  - Reduced penetration of the energy efficiency programs.

- Renewable Energy Scenario

  The Renewable Energy Scenario incorporated targeted renewable alternatives, including wind, landfill gas, anaerobic digesters, and generation resources fueled by cellulosic biomass resources. Combined heat and power (CHP) resources, not necessarily fueled by renewable resources, were also included in this scenario. The Renewable Energy Scenario included the following assumptions:

  1. Landfill gas, anaerobic digestion, wind, cellulosic biomass, and CHP resources were scheduled in, according to an assumed portfolio standard for renewable resources and an assumed rate of growth for CHP.
  2. Wind energy was assumed to have a capacity value, on peak, of 12.5 percent of nameplate capacity.
  3. Central Station options remained the same but they were re-optimized after taking into account the schedule of Renewable Energy options.

  The following sensitivities were performed for the Renewable Energy Scenario:

  - High Load sensitivity represented a 1.61 percent annual average demand growth rate.
  - Low Load sensitivity represented a 0.76 percent annual average demand growth rate.

- Energy Efficiency with Renewable Energy Scenario

  The Energy Efficiency with Renewable Energy Scenario combined the scheduled resource additions shown in the Energy Efficiency and Renewable Energy Scenarios. The Energy Efficiency with Renewable Energy Scenario contained the following assumptions:

  1. Energy efficiency programs were scheduled in, and the program cost was incorporated into the present value cost calculation.
  2. Approximately 570 MW of direct load control was included.
  3. Landfill gas, anaerobic digestion, wind, cellulosic biomass, and CHP resources were scheduled in, according to an assumed portfolio standard for renewable resources and an assumed rate of growth for CHP.
  4. The Central Station options remained the same, but were re-optimized after taking into account the energy efficiency options scheduled.

  The following sensitivities were performed for the Energy Efficiency with Renewable Energy Scenario:

  - High Load sensitivity represented a 1.61 percent annual average demand growth rate.
  - Low Load sensitivity represented a 0.76 percent annual average demand growth rate.
  - Reduced penetration of the energy efficiency programs.

- Combustion Turbines Only Scenario

  The final scenario modeled was that of an expansion plan limited to combustion turbines alone.

  The following sensitivities were performed for the Combustion Turbines Scenario:

  - High Load sensitivity represented a 1.61 percent annual average demand growth rate.
  - Low Load sensitivity represented a 0.76 percent annual average demand growth rate.

The detailed results from the modeling scenarios and sensitivities are discussed in the 21st Century Plan and the presentation by NewEnergy Associates on their expansion planning results. The results from the expansion plans for the different scenarios for the base case demand assumptions are summarized in Table 8.4-2 and Table 8.4-3.

The 21st Century Plan concludes that Michigan needs to provide additional baseload generating capacity to meet the forecasted demand. Several significant conclusions include:

- Michigan's peak electric demand is forecast to grow at approximately 1.2 percent per year for the next 20 years. At this rate, and given the long lead-time necessary for major plant additions, additional baseload generation is projected to be necessary as soon as practicable but no later than 2015.
- Extensive modeling of Michigan's electric utility industry demonstrates the need for additional electric generating resources in order to preserve electric reliability and provide affordable energy over the next 20 years. This modeling outcome is confirmed even in the presence of increased use of energy efficiency and renewable resources.
- This same modeling outcome is also confirmed in the presence of expanded transmission and access to external markets, and reflects the diminishing availability of the Midwest ISO regions baseload generation capacity.
- Recent estimates show that the cost of natural gas (or equivalent fuel) is often setting the wholesale on-peak prices within the Midwest ISO region. If regulated baseload capacity is not increased in the near future, natural gas prices will drive up wholesale costs and market prices for an increasing number of hours each year.

Extensive modeling of Michigan's electric utility industry demonstrates the need for additional electric generating resources in order to preserve electric reliability and provide affordable energy over the next 20 years, and beyond. This modeling outcome is confirmed even in the presence of increased use of energy efficiency and renewable resources. It is also confirmed in the presence of expanded transmission and access to external markets, and reflects the diminishing availability of Midwest ISO region's baseload generation capability. As discussed in the 21st Century Plan, this need can be met with new nuclear generating plants. The use of new nuclear is considered in the expansion models for the post-2015 planning period. A major advantage of nuclear technology is that modern nuclear reactors produce virtually no air emissions. For all cases where a modest carbon dioxide cost is assumed, nuclear is base load technology of choice.

Section 9.2 contains a more detailed discussion of energy alternatives to meet the projected need identified.

8.4.2 Other Benefits of New Nuclear Capacity

In addition to the information in the 21st Century Plan demonstrating that there is a need for new baseload generation in the State of Michigan and the ability of a new nuclear generating unit to meet this need, there are other benefits from operating a new nuclear facility in the State independent of the need for power. These other benefits are discussed below.

8.4.2.1 Need to Diversify Sources of Energy

Fuel diversity helps to protect consumers against the threat of supply disruptions or price volatility. With America's demand for electricity expected to grow 40 percent by 2020, meeting the nation's growing demand for reliable, affordable electricity will require the continued utilization of all domestic energy resources. This includes coal, which is the primary source of the electricity that powers America's homes and businesses.

- Coal provides half of America’s electricity generation and more than twice as much as the next-highest contributor — nuclear. In addition, coal is the largest single source of energy production at more than 31 percent of the total. (Reference 8.4-4)
- As discussed in Section 8.3, within Detroit Edison’s service area, coal provides 57 percent of the electricity generation, natural gas provides 23 percent, oil provides 11 percent, and nuclear provides 9 percent. In the METC, coal provides 24 percent of electricity generation, natural gas provides 48 percent, oil provides 6 percent, hydro provides 16 percent, and nuclear provides 6 percent.

A new nuclear generating unit in the State of Michigan will help to equalize the contributions from the different fuel sources. New generation in the State of Michigan also allows the state to avoid undue reliance on energy produced by other states.

8.4.2.2 Potential to Reduce Average Cost of Electricity to Consumers

As discussed above, natural gas-fired units represent approximately 29 percent of the electricity generating capacity in the State of Michigan. These units were built by independent power producers (IPPS). Many IPPs have subsequently gone through bankruptcy as a rise in natural gas prices over the past several years made even the most efficient units uneconomic to run for more than a few hours each year. Market prices driven by natural gas costs expose Michigan to volatile electricity prices. The addition of a new nuclear power plant to Michigan’s electricity supply would provide an additional needed source of baseload power that would help maintain stability of the cost of electricity for consumers.

Economics were a primary consideration in the 21st Century Plan for evaluating different options to meet the projected demand for new baseload generation. For each scenario evaluated in the plan (refer to Subsection 8.4.1, above) the generic resource options were first evaluated using screening curves to eliminate alternatives that would not be as economically viable. The screening curves calculate a full life-cycle, levelized present value cost, in $/kW-yr, for each resource alternative over a range of potential capacity factors. The calculations include overnight construction costs, fixed and variable operating costs including fuel costs, construction and operating cost escalations, allowance for funds used during construction, capital depreciation, property and income taxes, and insurance costs.

On the basis of the screening curves, for the Central Station Generation (Base Case), nuclear was "screened-out", among other technology options, from the resource optimization due to the levelized cost of nuclear units exceeding the costs of other technologies over the entire range of plant capacity factors.

However, for the Emissions Scenario, on the basis of the screening curve, the nuclear option is included in the resource optimization. The major difference that emerged from the Emissions Scenario was the added cost associated with emission allowances. As shown above, several sensitivities were included for the Emissions Scenario (High Load Growth, Low Load Growth, and Energy Efficiency). For the Base Emissions Scenario, and for each of the associated sensitivities, including nuclear units as part of the resource optimization due to the levelized cost is preferable to other technologies.

As part of the Detroit Edison Integrated Resource Plan (Reference 8.4-3) several scenarios and sensitivities, similar to those in the 21st Century Plan, were included:

- High and low load sensitivities
- Low and high gas price sensitivities
- Restricted and expanded transmission import scenarios
- Low reserve margin scenario
- Varying Renewable Portfolio Standard sensitivities
- Nuclear production tax credit scenario
- Varying Carbon Dioxide Tax sensitivities

The results of these scenarios and sensitivities clearly demonstrate that in all cases where a modest carbon dioxide tax was assumed, nuclear was selected over coal by a wide margin as the base load technology of choice. In the cases where no carbon dioxide cost was assumed, coal was selected over nuclear by a relatively small margin. In the Integrated Resource Plan, Detroit Edison assumes that some form of carbon dioxide cost is likely within the next ten years. This assumption is based on numerous issues and activities in recent years, including (1) several bills that have been introduced into the U.S. Congress addressing global climate change and greenhouse gas emissions, (2) legislation passed in several States to control emissions, and (3) the carbon dioxide exchange trading system for plant emissions adopted by the European Union. Given this assumption, the robustness of the nuclear base load selection is further evidenced by the fact that, in the analyses, a significant increase in nuclear capital cost was required before a base load coal option was selected over nuclear.

8.4.2.3 **National Need to Reduce Reliance on Fossil Fuels and Increase Energy Security**

The current national policy is to develop means to reduce dependence on fossil fuels. New baseload nuclear generating capacity is needed to enhance United States energy supply diversity and energy security, a key tenet of our National Energy Policy (Reference 8.4-5). That national policy is in support of new nuclear power is also apparent in Nuclear Power 2010 (Reference 8.4-6), which is a joint government/industry cost-shared effort to identify sites for new nuclear power plants, develop and bring to market advanced nuclear plant technologies, evaluate the business case for building new nuclear power plants, and demonstrate untested regulatory processes.

Fossil fuel-fired electrical generation plants produce more air emissions (e.g., nitrogen oxides, sulfur dioxide, and carbon-dioxide) associated with air quality, climatic affects, aesthetic, and health concerns than nuclear energy. The power generation sector accounts for the following emissions in the United States with respect to all industrial sources:

- 64% sulfur dioxide
- 26% nitrogen oxides
- 33% mercury
- 36% carbon dioxide

The State of Michigan is also concerned about emissions from fossil fueled electrical generation plants (Reference 8.4-1, Appendix II, Section 2.5). Michigan's coal-fired generating units emit approximately 80 million tons of carbon dioxide emissions annually, or an estimated 40 percent of the State's total emissions (Reference 8.4-7). Clean Air Act Amendment (CAAA) programs will likely require significant investment in existing generating plants to meet emission caps and may limit technology choices for new generating plants. These investments and possible choice limits are needed because coal-fired electric generators are major sources of sulfur dioxide, nitrogen oxides, particulates, and other air toxics, like mercury. In varying degrees, but to a lesser extent, diesel, fuel oil, and natural gas-fired generating units also emit these contaminants. These air pollutants affect human health, property, and the environment in multiple ways, and, therefore, are subject to multiple control programs. Air emission standards are an additional complexity and uncertainty for electric generation planning.

Beyond water vapor, modern nuclear reactors produce virtually no air emissions. Nuclear power generation, therefore, leads to significant local, national, and global air quality benefits.

8.4.3 **Summary of Need for Power**

As clearly shown in Table 8.4-1, the State of Michigan has a current need for new baseload capacity and this need is projected to increase. Michigan's present baseload generating units are an average of more than 48 years old. As discussed in Section 8.3, modeling for the development of the Michigan 21st Century Electric Energy Plan assumes that older, less efficient units, totaling 3755 MW of capacity, will be retired by 2025. The last new baseload plant in the State of Michigan began commercial operation more than 18 years ago. In recent years, new electric generation in

Michigan has been limited to natural gas-fired facilities. Natural gas-fired units represented about 10 percent of the State's generating capacity in 1992, but now represent approximately 29 percent of that generating capacity. These units were built by independent power producers (IPPs). Many IPPs have subsequently gone through bankruptcy as the rise in natural gas prices over the past several years made even the most efficient units uneconomic to run for more than a few hours each year. Market prices driven by natural gas costs expose Michigan to volatile electricity prices.

The proposed Fermi 3 (approximately 1600 MW) would provide for this need for baseload generation. Being a nuclear unit, the proposed Fermi 3 is strategic in that it helps reduce reliance on fossil fuels. Currently, the State of Michigan relies heavily on electrical generation from coal and natural gas. A new nuclear unit would diversify the energy supply for the State of Michigan.

In addition, using nuclear power for electrical generation reduces the emission of air pollutants. Beyond water vapor, modern nuclear reactors produce virtually no air emissions. Nuclear power generation, therefore, leads to significant local, national, and global air quality benefits.

8.4.4 References

8.4-1 Lark, J. Peter, Chairman Michigan Public Service Commission, "Michigan's 21st Century Electric Energy Plan," Submitted to Honorable Jennifer M. Granholm, Governor of Michigan, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm, accessed 18 January 2008.

8.4-2 NewEnergy Associates, "Expansion Plan Results," http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/expansion_results.pdf, accessed 18 January 2008.

8.4-3 State of Michigan, Before the Michigan Public Service Commission, Case No. U 15244, "Qualifications and Updated Direct Testimony of David B. Harwood."

8.4-4 America's Power, "Half of Our Electricity Comes From Coal," http://www.americaspower.org/Issues-Policy/50, accessed 17 June 2008.

8.4-5 The White House, "National Energy Policy," http://www.whitehouse.gov/energy/National-Energy-Policy.pdf, accessed 17 January 2008.

8.4-6 U.S. Department of Energy, "Nuclear Power 2010," http://www.ne.doe.gov/np2010/neNP2010a.html, accessed 17 January 2008.

8.4-7 Carbon Dioxide Information Analysis Center, "Estimates of Annual Fossil-Fuel CO2 Emitted for Each State in the U.S.A. and the District of Columbia for Each Year from 1960 through 2001," http://cdiac.ornl.gov/trends/emis_mon/stateemis/emis_state.htm, accessed 18 January 2008.

Table 8.4-1 Reserve Margin Analysis (Reserve Margin with No Capacity Additions)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak Demand (MW)	22,302	22,598	22,885	23,066	23,334	23,612	23,925	24,198	24,487	24,778
Installed Capacity (MW)	26,017	26,017	26,017	26,017	26,017	26,017	26,017	25,897	25,897	25,601
Reserve Margin (%)	16.66	15.13	13.69	12.79	11.50	10.18	8.75	7.02	5.76	3.32
Capacity Shortage (MW)	---	---	300	509	817	1137	1496	1930	2263	2893

Source: Reference 8.4-1, Volume II, Chapter 1, Table 10

Table 8.4-2 Summary of Scenarios and Sensitivities

	Scenario	10-Year Total Capacity Additions (MW)	20-Year Total Capacity Additions (MW)	10-Year Ending Reserve Margin (%)	20-Year Ending Reserve Margin (%)
Central Station		**3,440**	**11,260**	**15.26%**	**15.52%**
Sensitivity Analyses	High Load	6740	15,040	15.26%	15.63%
	Low Load	660	7640	17.28%	15.95%
	Reduced Import	3440	11,220	15.26%	15.40%
	Expanded Transmission	2660	10,330	12.53%	12.56%
Emissions		**3440**	**10,760**	**15.26%**	**16.04%**
Sensitivity Analyses	High Load	6760	14,240	15.33%	15.26%
	Low Load	320	7480	15.96%	17.69%
	Renewable & Energy Efficiency	3026	10,079	16.25%	16.89%
	Energy Efficiency Only	3249	10,261	16.09%	16.53%
Renewable Energy		**3370**	**11,218**	**15.97%**	**16.28%**
Sensitivity Analyses	High Load	6699	14,698	15.98%	15.48%
	Low Load	599	7238	18.07%	15.55%
Energy Efficiency		**3,249**	**10,581**	**16.09%**	**15.73%**
Sensitivity Analyses	High Load	6569	14,241	16.08%	15.45%
	Low Load	1609	6781	23.11%	15.53%
	Reduced Energy Efficiency Penetration	3267	10,700	15.69%	15.36%
Energy Efficiency with Renewable Energy		**3028**	**10,359**	**16.25%**	**15.95%**
Sensitivity Analyses	High Load	6188	13,899	15.69%	15.28%
	Low Load	2208	6579	26.70%	15.86%
	Reduced Energy Efficiency Penetration	3386	10,518	17.10%	15.70%
Combustion Turbines Only		**3520**	**11,200**	**15.54%**	**15.34%**
Sensitivity Analyses	High Load	6720	14,880	15.20%	15.18%
	Low Load	320	7680	15.96%	16.09%

Source: Reference 8.4-1, Volume II, Chapter 1, Table 11

Table 8.4-3 Comparison of Scenarios Using Base Case Demand Assumptions (2006 – 2025)

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Nuclear/IGCC (MW)	Renewable Resources and Energy Efficiency (MW)
Central Station	1760	500	9000	0	0
Emissions	1760	1000	2000	6000	0
Energy Efficiency	1280	0	6500	0	2801
Renewable Energy	1920	500	8000	0	798
Energy Efficiency with Renewable Energy	1760	0	5000	0	3599
Combustion Turbines Only	11,200	0	0	0	0

Source: Reference 8.4-1, Volume II, Chapter 1, Table 19