

CHAPTER 2

Capacity Need Forum Update Workgroup Resource Assessment

1. Introduction

The CNF Update Workgroup was charged with reviewing and providing updates to five principal data and analysis sections of the Capacity Need Forum (CNF) study from 2005. First, it 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. It also included a review of siting issues, especially matters related to air permit requirements.

Second, the Workgroup was charged with reviewing the transmission analysis performed for the CNF, confirming the simultaneous, on-peak transmission capability, and determining the amount of capability available for reliability support for the Lower Peninsula. It was also tasked with assessing the follow-on Michigan Exploratory study.

Third, the Workgroup was also responsible for electric reliability assessments for regions within Michigan.

Fourth, the Workgroup provided an updated twenty-year electric sales and peak demand forecast for Michigan. As in the CNF, the long-term forecast was provided for each of the three geographical regions within Michigan.

Fifth, the Workgroup managed the expansion modeling, provided fuel and emission cost forecasts, and developed model scenarios and sensitivities. A description of the modeling efforts are presented in Chapter 1.

The Workgroup followed the same process used in the Capacity Needs Forum and relied on data, analysis, and narrative from that effort where appropriate.

2. Resource Assessment: Central Station Generation Options

2.1 Current Inventory

The state's inventory of generating options has not changed since the CNF report was issued in January 2006. In 2004, Michigan relied on coal and nuclear fueled baseload generation units for about 83 percent of its annual electricity production, natural gas for about 13 percent of its annual production, and from hydro and other sources, for about 4 percent of its generation.

Table 1 summarizes the currently operational generating units in Michigan. It excludes American Electric Power's (AEP) Cook nuclear units in Southwestern Lower Michigan, which collectively represent approximately 2,000 megawatts (MW) of generating capacity. The Cook

units are excluded because the plant is committed to the PJM system and so is not dispatched or available to the Midwest Independent System Operator (MISO) for purposes of meeting non-AEP Lower Peninsula power needs.

Table 1 is organized around the geographical approach of assessing electric generating capacity needs by region within Michigan. The three regions includes: (1) Southeast Michigan, principally the Detroit Edison service territory and now the International Transmission Company (ITC) service territory; (2) the balance of the Lower Peninsula excluding the area served by PJM, or the Michigan Electric Transmission Company service territory, including Wolverine (METC); and (3) the Upper Peninsula, the American Transmission Company Zone 2 (ATC Z-2). Although METC and ITC recently merged, the use of geographical regions remains valid since it respects transmission constraints between regions.

Table 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	1970	1,240.8	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	27,984	28,535	5,843.6	2335.8	3251.9	859
REGION % of TOTAL	46.2%	46.3%	49.5%	53.7%	51%	32%

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 Utilities						
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	7,017	7,171	1,696	967.2	1,215.4	117
Ownership: Municipals / Cooperatives / 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	13,981	14,219	2,700.5	991.3	1,427.1	410
MICHIGAN TOTAL	27,984	28,535	5,843.6	2335.8	3251.9	859
REGION % of Total	50%	49.8%	46.2%	42.4%	43.9%	47.7%

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 Utilities						
Steam Generator	613	613	90	25	68	9
Hydro	24	28	24	24	24	1
Pumped Storage	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: Municipals / Cooperatives / 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	5,516	5,548	763.9	4.3	139.5	156
REGION TOTAL	1,081	1,098	251.1	90.7	165.2	174
MICHIGAN TOTAL	27,984	28,535	5,843.6	2335.8	3251.9	859
REGION % of Total	3.9%	3.9%	4.3%	3.9%	5.1%	20.3%

2.2 Technology Options

The Workgroup adopted the same central station options used in the CNF and added a pulverized coal option. The options included the following types of units:

- Pulverized Coal
 - sub-critical
 - super-critical
 - ultra super-critical
- Circulating fluidized bed (CFB)
- Integrated gasification combined cycle
- Integrated gasification combined cycle with Powder River Basin (PRB) coal
- Nuclear
- Natural Gas
 - simple cycle combustion turbines
 - combined cycle combustion turbines

A description of each technology can be found on pages E-3 through E-7 of the CNF's Central Station Workgroup report from 2005.¹¹ The discussion of generating technologies in this report will be limited to changes that have occurred since the CNF report was published.

The CNF report included data on sub and super-critical pulverized coal plants. Since release of the CNF report, AEP has announced plans to construct an ultra-critical pulverized coal-fired generation plant in Arkansas. Ultra super-critical (USC) pulverized coal plants operate at pressures in excess of 3,600 lbs. and at temperatures above 1,050 degrees Fahrenheit. Generally, operating efficiencies improve as temperatures and pressures are increased. More efficient operating cycles mean less fuel is consumed for each megawatt hour (MWh) produced, lowering fuel costs and emissions related costs. For this report, it was assumed an ultra-critical design heat rate of 8,000 British Thermal Units (BTUs) compared to 9,496 BTUs for a sub-critical unit. Ultra and super-critical plants, however, require more expensive metal alloys that can tolerate the higher temperatures and pressures at which these plants operate.

The more expensive metals necessary for ultra and super-critical plants require greater capital costs for these plants. Coal prices in the U.S., however, have been comparatively low and stable and have actually fallen in real terms since the mid 1980s. Over the past 30 years, this capital cost - fuel cost tradeoff – has resulted in no clear advantage of super-critical technology over sub-critical technology in the U.S. As a result, mixes of both types of plants were built and, although both continue to be planned for the future, there appears to be a preference to build large super-critical units. Both technologies have performed well throughout the world. Since both super and ultra super-critical plants operate more efficiently than sub-critical plants, they emit fewer emissions for each megawatt hour of electrical production. Nevertheless, any new pulverized coal plant built today would require a scrubber for sulfur dioxide (SO₂) control, a SCR system for NO_x removal, and a fabric filter or electrostatic precipitator for particulate

¹¹ Report available online at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/central/finalreportjan_2006.pdf

control. The implications of Michigan’s proposed mercury rules have not yet been determined and therefore the cost to install this control technology has not been included in the cost analysis summary table. However mercury compliance costs are estimated from emission allowance costs based on an 85 percent reduction. A further discussion of the new mercury rule issues can be found later in this report.

2.3 Technology Costs

The Technology Price Estimate table below summarizes the CNF Update Workgroup’s estimate of costs and typical emissions profiles associated with construction and operation for each type of plant described above. Plant construction costs include land, boiler, turbine and all other on-site infrastructures except for electrical switchyard components. The capital and operations and maintenance (O&M) costs associated with cooling water, fuel transportation and transmission connection costs are unknown until specific plant locations are selected, but have been included in the Workgroup’s estimate, as generic or typical costs. Transmission system upgrades necessary to move the power from a new plant to the electrical load centers is not included in any estimates provided in Table 2 and could vary widely dependent on plant location and current transmission design and loadings. For modeling purposes, estimated transmission system upgrade costs of \$77.56 per kilowatt (kW) are included in the resource expansion plans when evaluating the various scenarios and sensitivities.

Construction costs are provided as “overnight costs,” meaning that any interest costs to finance the plant during its construction period are not included, nor is the effect of inflation included in these overnight costs. Plant costs are assumed for a “green field site,” which means that these units are not being constructed at an existing power plant site and, therefore, are unable to take advantage of existing infrastructure. There will be limited opportunities in Michigan to add units at existing plant sites, the exact number of and cost advantage of these are unknown at this time.

The fact that many counties in southeastern Michigan have been designated as nonattainment for various environmental pollutants, as reflected in the pictorials below, means that extra measures or costs could be incurred to construct coal-fired power plants near the southeastern Lower Michigan load centers. In general, if a plant is sited in an attainment area it must meet Best Available Control Technology (BACT) standards and if it is sited in a nonattainment area it must meet Lowest Achievable Emission Rate (LAER) standards. One exception to this rule is that if an existing plant site issued in a nonattainment area and there is an ability to reduce other emissions at the site, then a netting strategy¹² for the new power plant at this site may be used and LAER would not be a mandated requirement. However, if a new plant is sited on a green field site that is located in a nonattainment area, any uncontrolled, regulated pollutant may need to be offset at another source site at a rate of 110 percent of the new site’s uncontrolled emissions.

¹² The new power plant’s emissions added to the reduced emissions from the site’s existing plant must be equal to or less than the emissions generated from the existing plant prior to the new plant being built.

Table 2: Plant Construction Costs

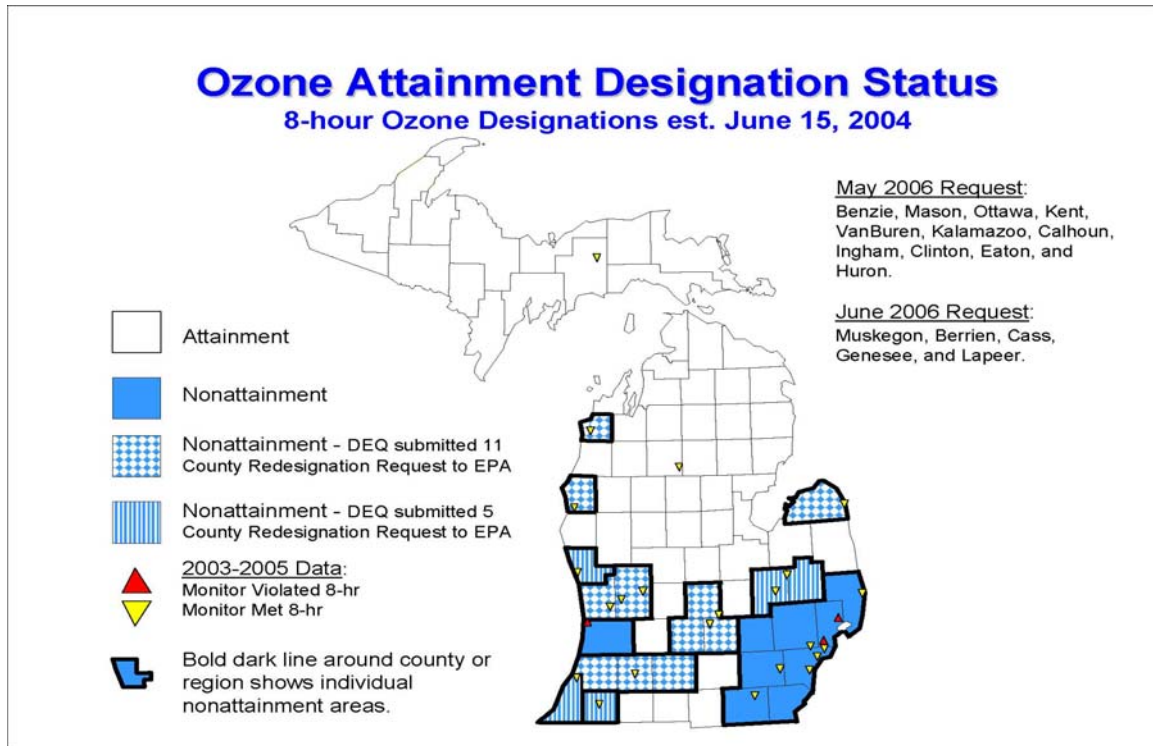
Technology	Size (MW)	Base Cost from (2003\$) (\$/kW)	Overnight Capital (2006\$)	Fixed O&M (2006\$)	Var. O&M (2006\$)	Design Heat Rate (Btu/kWh)
Pulverized Coal						
Sub-critical	500	1,230	1,478	44.26	1.86	9,496
Super-critical	500	1,290	1,551	44.91	1.75	8,864
Ultra-critical	500	NA ¹	1,675	47.16	1.84	8,000
Fluidized Bed	300	1,290	1,628	46.11	4.37	9,996
IGCC	550	1,350	1,785	61.30	0.98	9,000
IGCC - PRB Fuel	550	1,512	1,999	61.30	0.98	10,080
Nuclear	1000	1,957	2,352	69.93	0.55	10,400
Combined Cycle	500	440	529	5.57	2.19	7,200
Combustion Turbine	160	375 ²	425	2.19	3.82	10,450
¹ Ultra Critical PC plant was not studied in the CNF. ² Base Cost for combustion turbines derived from 2005\$ and not 2003\$.						

The costs shown in Table 2 were based on costs developed for the CNF, with the exception of the ultra-critical pulverized coal technology, which was added for the Plan consideration with costs derived from the EPA document - *Coal Based Technology Report* (EPA-430/R-06/006) July 2006. The construction cost estimates for the other technologies were originally estimated in 2003 dollars and are based on the EIA/DOE Annual Energy Outlook 2005, a U.S. Department of Energy and National Coal Council report entitled “*Opportunities to Expedite the Construction of New Coal-Based Power Plants*” and CNF working group member inputs. Cost estimates were increased from the CNF estimates by the rate of inflation plus a rate of 10 percent to represent the current major cost increases in steel, copper, and concrete commodity prices, and increased labor costs. Pulverized coal costs include flue gas desulfurization, a selective catalytic reduction (SCR) unit and a baghouse. Mercury control equipment construction costs and operating costs are not included in the above estimates. However, forecasted mercury allowance costs based on an 85 percent mercury reduction standard have been included in the modeling phase of this report. It should be noted that investment cost numbers can differ materially depending on the specific location of a new plant.

2.4 Technology Emission Characteristics

Figure 1 shows the status of ozone nonattainment counties in Michigan as of December 7, 2006. DEQ had previously requested that eleven counties be designated as attainment areas. This request has been approved and the counties of Ingham, Eaton, Clinton, Kent, Ottawa, Van Buren, Kalamazoo, Calhoun, Benzie, Mason, and Huron are now classified in attainment. The redesignation will be officially proposed in the *Federal Register*, and the public will have 30 days to comment on the proposed action after it is published. The redesignation request for Muskegon, Berrien, Cass, Genesee, and Lapeer is still being reviewed by Environmental Protection Agency (EPA).

Figure 1: 8-hour Ozone Nonattainment



After a review of emission profiles from several sources including EPA’s RACT¹³/BACT/LAER Clearinghouse, the Workgroup members decided to retain the unit emissions profiles developed for the CNF report. Those profiles are shown in Table 3.

2.5 Air Quality and Electric Energy Planning

Clean Air Act Amendment (CAAA) programs will likely require major investment in existing generating plants to meet emission caps and may limit technology choices for new generating plants. Retrofits to existing plants are needed because these programs did not exist when most of today’s major power plants were designed and built. Wisconsin Electric estimates it may have to spend in excess of one billion across its fleet to comply with new Federal air rules, including controls for NO_x, SO₂ and mercury. Detroit Edison has estimated its cost of compliance at up to \$1 billion. If these investments are not made, the utilities will need to purchase emission allowances or retire some plants.

These investments must be made because coal fired electric generators are major sources of SO_x, NO_x, 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.

¹³ Reasonably Achievable Control Technology.

Table 3: Typical Plant Emissions

Plant Typical Emissions (lbs/MMBtu ¹)					
	SO ₂	NO _x	Particulate	Hg	O ₂
Pulverized Coal					
Sub-critical	0.05	0.08	0.015	1.22E-06	201
Supercritical	0.05	0.08	0.015	1.22E-06	201
Fluidized Bed	0.02	0.10	0.015	1.22E-06	200
IGCC	0.03	0.06	0.006	8.05E-07	195
Nuclear	0.00	0.00	0.00	0.00	0.00
Combined Cycle	0.001	0.03	0.00	0.00	120
Combustion Turbines	0.001	0.03	0.00	0.00	120

1. MMBtu – million British Thermal Units is a standard unit of measurement used to denote both the amount of heat energy in fuels and the ability of appliances and air conditioning systems to produce heating or cooling. A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit. Since BTUs are measurements of energy consumption, they can be converted directly to kilowatt-hours (3412 BTUs = 1 kWh)

Air emission standards are an additional complexity and uncertainty for electric generation planning. Technologies available for construction may be constrained by permit requirements for BACT, LAER, New Source Performance Standards (NSPS), etc. Historically, permitting agencies have evaluated permit applications based upon the level of control placed on the process, and have not mandated that applicants evaluate other alternate processes which may be capable of achieving a lower level of emissions. This practice has been challenged recently but has been upheld through EPA guidance by EPA’s Environmental Appeals Board.

Michigan’s State Implementation Plan (SIP) for a Prevention of Signification Deterioration (PSD) program was filed with the Secretary of State on December 4, 2006, and went into effect immediately. Michigan formerly was delegated authority to issue PSD permits through the federal rules. The new state rules mirror, for the most part, the federal requirements. One advantage of the state program is that the federal administrative appeal process (i.e. the Environmental Appeals Board) will no longer apply in Michigan. Instead an administrative hearing before a state administrative law judge that is similar to any other contested case under Michigan’s program will apply. Michigan’s SIP will be officially proposed in the *Federal Register*, and the public will have 30 days to comment on the proposed action after it is published. Until Michigan gets SIP approval, both the state and federal PSD rules apply. Once the SIP is approved (sometime in 2007), all PSD permits will be issued under the state PSD rules only.

In recent years there have been appeal actions that have challenged the type of coal burning technology chosen by a permit applicant as well as the type of coal. Some groups have preferred adoption of integrated gasification combined cycle (IGCC) technology because its potential air emissions profile is assumed to be superior to pulverized coal and circulating fluidized-bed boiler (CFB) technologies. Recent EPA guidance and the EPA’s Environmental Appeals Board decision have determined that IGCC need not be considered as an alternative technology to conventional coal-fired power plants. However, during recent permitting activities in EPA’s

Region V, applicants have been asked by state agencies, to consider IGCC, but have not been forced to use the technology since some would not consider IGCC to be “commercially available” technology. Nevertheless, permit requirements are not dependent on commercial availability but rather on the definition of the production process. Notwithstanding the debate over the reliability and cost of IGCC technology, a permitting agency that advances an air use permit would, as a practical matter, likely need to undertake a comprehensive and convincing review of IGCC technology as there is a very high likelihood that the permitted use of the conventional pulverized coal-burning technology (Pulverized Coal-Fired Combustion and Circulating Fluidized Bed Combustion) might again be contested or appealed. While there appears to be a move towards IGCC technology with several utilities announcing plans to build new IGCC generating capacity in other states, this technology should be assessed like all other resources by considering its costs, emissions profiles, operating characteristics, and risk profile.

Irrespective of the recent challenges based on different production technologies, new standards may evolve from conventional technology. Recently, American Electric Power Company has announced plans to build an ultra super-critical pulverized coal plant in Arkansas. Since this technology is not fundamentally different from sub or super-critical pulverized coal units, it is conceivable that this technology may be adopted as the BACT standard for conventional coal fired generating units.

Risk management requires that planners anticipate evolving standards. For example, it is reasonable to anticipate that concerns over climate change will result in mitigation or control requirements for carbon dioxide emissions from the electric generating industry. Even though emissions standards for CO₂, along with other greenhouse gases, do not currently exist in the United States, it is reasonable to consider the likelihood that some type of carbon mitigation requirements will exist over the planning horizon. Any type of greenhouse gas emissions regulations could prove to be costly to coal units because coal generation is a major source of carbon dioxide emissions. Michigan’s coal fired generating units emit approximately 70 million tons of carbon dioxide emissions annually, or an estimated 40% of the state’s total emissions.¹⁴ This adds uncertainty to the planning process and the potential for additional control costs in the future. Identifying and attempting to manage this risk is one of the primary roles of the planning process.

2.6 Natural Gas Infrastructure

Natural gas fueled generation accounts for approximately 29 percent of Michigan’s electric generating capacity. This represents a large increase since the early 1990s, when it amounted to approximately 10 percent of the state’s capacity. Michigan’s experience with increased reliance on natural gas for generation capacity is not unique. Throughout the United States, most new generation added over the past 10 years has been gas-fired. Natural gas accounts for about 40 percent of the nation’s electrical generating capacity.

¹⁴ Data for Michigan CO₂ emissions was sourced from Oak Ridge National Laboratory, U.S. DOE, "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," Trends: A Compendium of Data on Global Change, 2004, accessed at http://cdiac.ornl.gov/trends/emis_mon/stateemis/emis_state.htm, January 22, 2007.

In various regions of the U.S., questions have been raised about the ability of the natural gas transmission and distribution system to supply this growth in natural gas demand. The MPSC Staff has undertaken a brief analysis to assure that the growth of natural gas generation has not stressed Michigan's delivery system. Generally, the Michigan system can accommodate limited, additional gas-fired generation, depending on where the generation is sited.

The viability of new, gas fired generation in Michigan is dependent on numerous considerations and assumptions, each of which must be evaluated. Some of the more important considerations are proximity to gas pipeline infrastructure, proximity to electric grid, plant load factor, pipeline capacity and pressure, gas supply into the state, available capacity on interstate pipelines and land availability.

The MPSC Staff reviewed the gas delivery system of the state's two largest combination utilities – Consumers Energy and Detroit Edison/MichCon. These two utilities are the most capable of accommodating a major natural gas-fired generating plant. Siting for a new plant was, likewise, confined to the southern Lower Peninsula. It was also assumed that new gas-fired generation would be used for peaking and would only operate for a limited time during the hot summer months.

Based on Staff's discussions with interstate natural gas pipeline operators and Michigan natural gas distribution companies, and based on data reviewed by the MPSC Staff, it is estimated that each utility's system has approximately three sites suitable for natural gas fired generation. These are sites where adequate pipeline capacity and pressures exist, adequate electric facilities are available and land appears to be available to accommodate a plant site. This does not mean, however, that three plants can be built on each utility's system. It appears that each utility can support up to two plants under certain conditions and under the assumption that such plant(s) would be used for peaking and only operate for a limited time during the hot summer months. This would not be the case if gas-fired generation were intended for baseload purposes.

This review did not include a study of long-term gas supply available for electric generation. However, it did include discussions with the major gas transmission companies delivering gas to Michigan and it revealed that limited additional capacity is available on existing pipelines. Trunkline Gas Co. currently has some available capacity and ANR Pipeline Co. currently has a fair amount of capacity available on its east pipeline leg. The remaining pipeline companies indicate that no further capacity is available at this time (summer 2006) or in the near future. Although the availability of future capacity is unknown, gas flowing on existing pipelines that is not committed to generation may be delivered to new electric generation sites if short term arrangements are made with the current owner.

The addition of new gas-fired electric generation will impact the injection of gas into underground storage. However, the short term nature of the peak loads that require gas fired generation will not adversely impact storage levels over the entire injection cycle. During the use of gas-fired generation, storage injections will be cut back or curtailed entirely depending on the amount and duration of the peak electric load. Once electric loads return to normal and the gas-fired generation is taken off line, gas storage injections will resume. It is anticipated that these brief interruptions in gas storage injections will not adversely impact the utilities' ability to

fill gas storage fields by the end of the injection cycle. It should be stressed that operating any new, large natural gas fueled generating plants for extended periods of time in the summer months could impair the ability of the state to fill gas storage to levels needed for winter operations. While not likely to cause the natural gas systems to be less reliable, failure to fill the storage system for each winter season could increase the natural gas costs for gas utility customers.

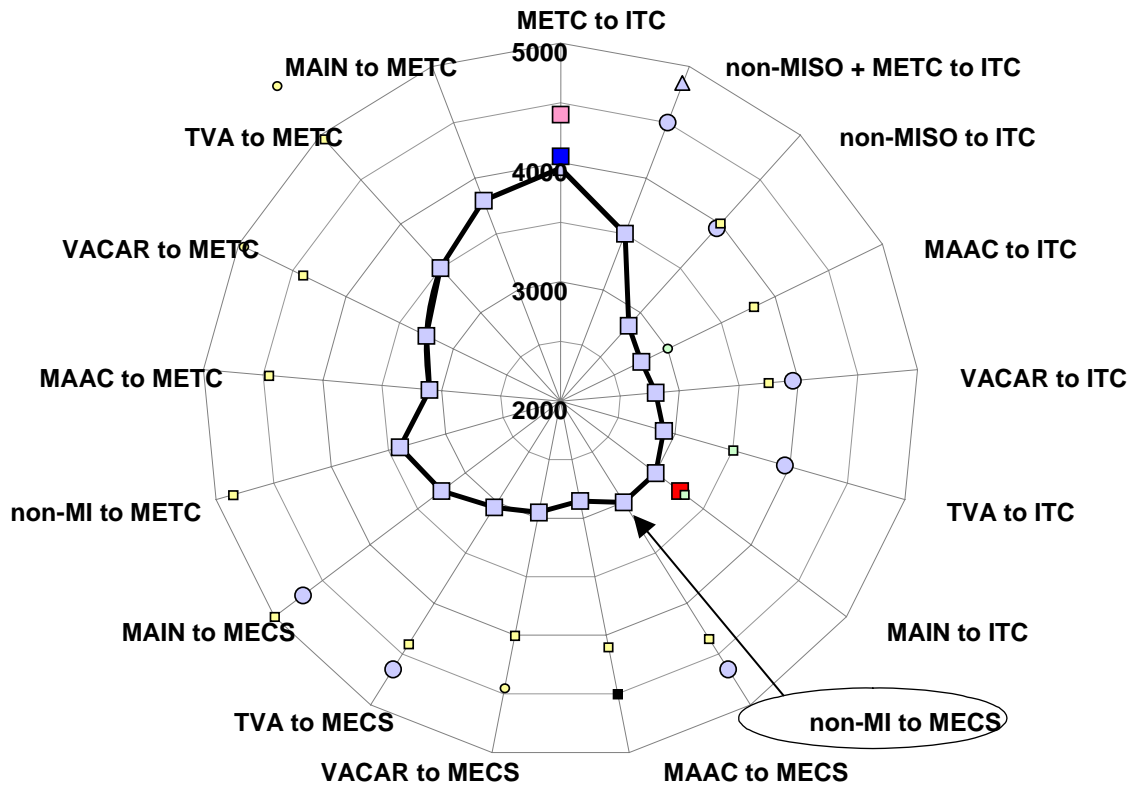
3. Transmission

The CNF Update Workgroup was also responsible for reviewing the transmission assessment and estimates provided to the CNF. The original interface capabilities were provided by the CNF's Transmission and Distribution Team for the 2009 forecast year. The CNF Transmission and Distribution Team also identified transmission upgrades that could be implemented to increase transmission transfer capability within Michigan and into Michigan. Finally, the CNF Transmission and Distribution Team also reviewed issues that may have an impact on the state's ability to utilize or expand its transmission system. Workgroup participants concluded that the CNF's base and contingent import capacity estimates remain reasonable estimates for Michigan's 2009 on-peak, simultaneous transmission capability.

The Lower Peninsula's import capability estimate was made for 2009 and was based on MISO's MTEP05 (MISO expansion plan) plan. The Upper Peninsula's estimate was also made for 2009 and was based on the American Transmission Company's (ATC) Northern Umbrella Project (NUP) schedule. Extensive PowerFlow modeling was conducted by ITC and ATC on behalf of the CNF. A significant contingency identified in the CNF was power flow through Michigan to Ontario, which served as a modeling sensitivity. A detailed description of the PowerFlow modeling procedures and results can be found in the CNF's Transmission Workgroup. For this report, figures are included which show simultaneous import capabilities into Michigan's Lower Peninsula for the CNF base year of 2009 for the base 3,000 MW import capability (Figure 2), the 1,500 MW reduction (Figure 3), and 2009 transmission capability for the Upper Peninsula (Figure 4). The transmission discussion in this report is limited to items that have changed or emerged since release of the CNF report.

Figure 2: Lower Peninsula Transmission Import Capabilities from Neighboring Markets

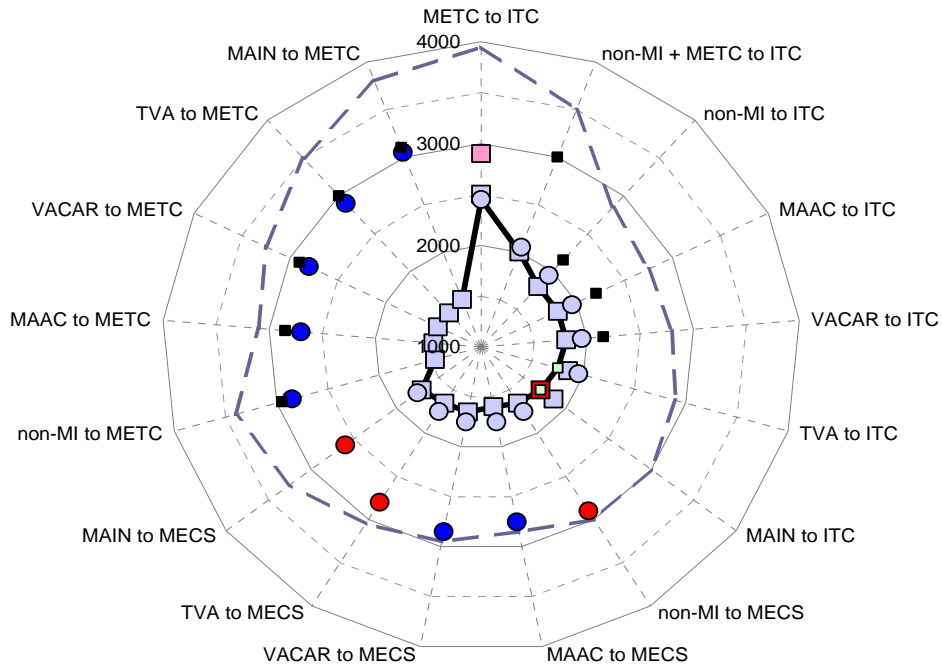
Currently Planned System⁴
2009 Summer -- Total Normalized¹ Import Capabilities for Various Incremental Transfer Scenarios



- Notes: ¹ Values shown are MW, normalized to represent import capability if the other entity in MECS were importing 0 MW from Michigan. Actual Traditional Base-Case Imports: ITC = +1,860 MW, METC = - 510 MW (representing transmission across METC to ITC), and MECS = +1,350 MW.
- ² Only the first few limits are shown and the most restrictive limits are shown for groups of limits that are highly correlated. The heavy black line connecting data points near the center of the graph represents the first limit on each transmission interconnection between Michigan's Lower Peninsula and neighboring systems. Reading outward from the center along each spoke on the graph, subsequent marks indicate what the next transmission limit would be on each interconnection if the transmission system were upgraded in some way to remove the previous transfer constraint.
- ³ Contingencies considered included: units dispatched off; units tripping off; single transmission; and single transmission with units dispatched off.
- ⁴ Traditional Base-Case has 0 MW flowing between Michigan and Ontario, controlled by phase-shifting transformers.

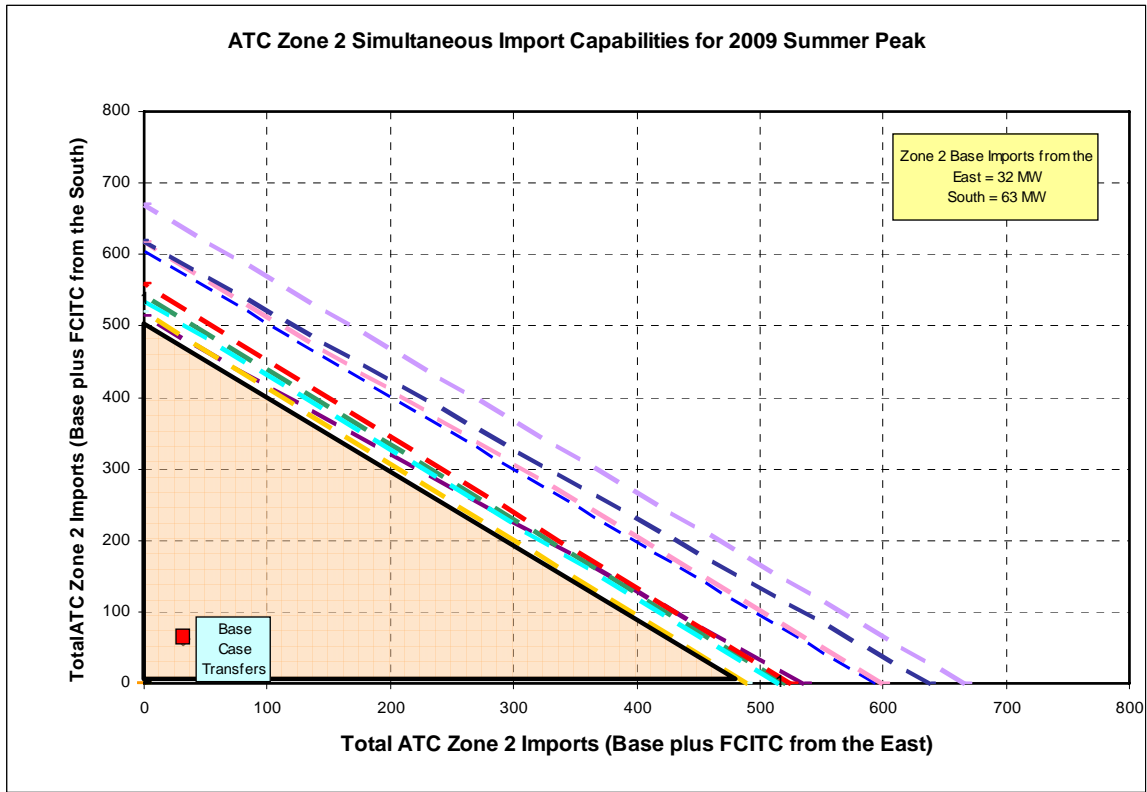
Figure 3: Impact of 1,500 MW Flow from Michigan to Ontario⁴

2009 Summer -- Total Normalized¹ Import Capabilities for Various Incremental Transfer Scenarios



- Notes:
- 1 Values shown are normalized to represent import capability if the other entity in MECS were importing 0 MS's. Actual Base Case imports ITC=1860, METC=-510 and MECS=1350.
 - 2 Only the first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.
 - 3 Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.
 - 4 Base Case has OMSs flowing between Michigan and Ontario controlled by phase shifting transformers.

Figure 4: ATC Zone 2 Simultaneous Import Capabilities for 2009 Summer Peak



3.1 Recent Transmission Developments

One major change in the assumptions adopted for the CNF has been made for the 21st Century Energy Plan. The CNF base case assumed that 3,000 MW of on-peak transfer capability was available into Michigan for 2009. While this estimate has not changed, approximately 800 MW have been reserved for firm transmission service by parties outside of Michigan. Therefore, the amount of transfer capability available for reliability purposes for Michigan is not more than 2,200 MW.

There are two factors which can reduce allowable transfer capabilities to lower levels. One is Transmission Reliability Margin (TRM), which is used by the Midwest Independent System Operator (MISO) 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 MISO-PJM Coordination Agreement requires that MISO allocate some capacity to PJM member utilities. At this time, those amounts have not been finalized.

For economy energy purposes, 3,000 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

2,200 MW. In addition to these firm reservations, Michigan remains subject to loop flows that can further restrain the amount of transmission into Michigan.

3.2 Michigan Exploratory Study

The CNF report identified two classes of transmission upgrades to enhance Michigan's electric transmission capability. The first set was referred to as TIER I upgrades and represented 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. Although some of the TIER I upgrades include line reconstruction, many of these upgrades do not result in increasing the overall amount of "wire in the air." As such, these TIER I upgrades could result in the system being pushed harder, with resultant voltage issues and losses becoming a growing concern. Voltage limitations may preclude these apparent transfer enhancements from being fully realized and increased losses may erode some of the apparent capacity gain.

The second set of upgrades, referred to as TIER II upgrades, initially consisted of three possible major, new transmission projects running from the Detroit area to Southwestern Michigan. The three options included a new double circuit 345 kilovolt (kV) line, a new single circuit 765 kV line, and a 2,500 MW direct current (DC) line. These competing options prompted MISO to commence the Michigan Exploratory Study as part of MISO's Midwest ISO Transmission Expansion Plan (MTEP 2006) process.

The Michigan Exploratory Study focused on two alternatives for the proposed transmission expansion. The initial proposal was either for a 2,500 MW direct current (DC) line or an alternative extension of the 765 kV system from southwest Michigan to northwest Detroit. This DC option is included as one of the Plan's sensitivities, the expanded transmission sensitivity of the central station scenario. The model assumption is that the DC line would be operational in 2009 at a cost of \$800 million.

Recently, the Midwest Independent System Operator has released a report on the two options. The report reviewed by the MPSC Staff focused exclusively on the net economic benefits of two competing transmission line proposals. The MISO report indicates that there is a net, positive benefit to Michigan in completing either project. Much of the benefit comes from the modeling results that assume the increased transfer capability provided by these new transmission projects will allow for the maintenance of a loss of load probability (LOLP) of 0.1 with a 10 percent reserve margin opposed to the Plan assumption of 15 percent. MISO's draft report has prompted Staff to add a scenario increasing transfer capability by 2,500 MW to the Plan modeling program. In this new scenario, Michigan's overall reserve margin is decreased from 15 percent to 12 percent. The 2,500 MW increase in transfer capability is not tied to either the DC or 765 kV line option, either of these options can be used to achieve this level of transfer capability increase. Contrary to MISO's study, Plan modeling projected a higher cost associated with the new transmission line when compared to in-state construction.

While either option could be pursued, MISO and ITC have indicated that construction of the DC option might be able to be completed more quickly than the alternating current (AC) option. The

primary driver of these potential timing differences is the time to acquire necessary new rights-of-way. A preliminary analysis revealed it might be possible to site DC primarily on existing rights-of-way while the 765 kV would require substantial new right-of-way. The MISO analysis found that under an assumed project implementation time for the 765 kV that is four years longer than the DC, the DC would have more net benefit. However, if the 765 kV is completed in the same time period as the DC, the 765 kV would have higher net benefits.

While it is not clear exactly what project delay results in the cross over between the net benefits of the 765 kV vs. DC, it is clear that the length of time to implement either of these options is an important consideration that would need further analysis before a recommendation involving either of these options can be made. A substantial portion of the proposed line's benefit is relieving reliability issues in southeastern Michigan. Even with a lower demand forecast, MISO projections indicate that reliability constraints are likely to be violated in the ITC service territory as early as 2009 on a stand alone basis. Based on the information presented by MISO and ITC, the base cost for the DC line option is \$800 million. These costs would be allocated in accordance with prevailing MISO tariff provisions, which may result in sharing of project costs over wider areas.

In early November 2006, ITC & AEP announced plans to jointly study a 765 kV loop through Michigan's Lower Peninsula that would potentially be in both ITC's and METC's service territories and link to AEP's existing 765 kV transmission infrastructure. The draft MTEP06 report includes this 765 kV loop as a proposed project with an estimated cost of \$2.5 billion and 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 MISO system operation tariff and may be sold to third parties on a first come – first served basis. A complete discussion of the energy market rules and tariff is beyond the scope of this study.

4. Electric Reliability Assessment

The purpose of reliability modeling is to determine whether existing native generation together with electric transmission transfer capability and available external support can reliability meet projected hourly peak load. Reliability modeling for the CNF was performed by MISO. The MISO Staff used the MARELI computer model along with data from last year's CNF workgroups to estimate future generating reliability in each region of the State.

Although a thorough reliability analysis was performed by MISO in 2005 for the CNF, two important changes have occurred that may change the results. First, the demand and energy forecasts have been reduced. (See the Electric Sales and Peak Demand Forecast in Section 5 for further information on the demand and energy forecasts.) Second, after discussions with ITC and MISO, the CNF Update Workgroup has concluded that approximately 800 MW of transmission capability has been reserved for an indefinite period of time for transmission through the Michigan system, and is, therefore, not available for Michigan's use.

Although reliability standards are not uniformly promulgated throughout the United States, a target of one day in 10 years loss of load probability (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, that other units from a reserve are available to meet the expected load.

The likelihood that a generating unit may be forced off-line is manifested in its forced outage rate. If the rate is high, there is a larger likelihood that the unit might not be available to meet load when needed. On the other hand, a low forced outage rate indicates that the unit is more likely to be available when needed. Because of the probabilities that plants may not be available when needed, large reserves would be necessary to be absolutely certain that all demand will always be met. There is a significant cost associated with building and maintaining necessary reserves that may frequently remain idle.

If one were willing to relax the requirement of 100 percent certainty that demand always be met and, instead, assume a slightly reduced probability that demand could always be met through generation, then reserves and associated costs could be reduced significantly. The reduced probability that one is willing to assume is a measure of generation reliability. As indicated previously, the most widely accepted level of reliability is the willingness to tolerate the probability that the "local" generation and the generation that could be imported is insufficient in one day out of 10 years to meet load in an area. This is the reliability standard that was adopted last year by the CNF for generation/transmission planning purposes, and the reliability standard used by MISO for the MARELI model runs. This standard was again adopted for the Plan.

The MARELI model is a probability based algorithm used to assess whether a geographic region's native generation, together with interruptible load, is sufficient to meet hourly peak loads, within the one day in 10 year LOLP tolerance. If the reliability criteria are met, the model gauges the excess import or export capability available. If the criteria are violated, it calculates how much additional imports are required to meet the criteria.

The model uses a probability distribution of available and operational generation in a region based upon each unit's forced outage rate. The distribution takes the form of an aggregate supply-capacity curve, running from a probability of 0 to 100 percent. The curve depicts the probability that a given level of demand can be met by generators collectively within the region. The LOLP sums the loss of load expectations – when supply is insufficient to meet demand - of daily peak hours over a year.

For the CNF study, owners of generation in Michigan reviewed and updated the generation data used by MISO, including capability and availability – incorporating forced outage experience for each plant. Hourly customer demands were supplied by all MISO load serving entities in Michigan, including investor owned electric utilities, cooperative electric utilities, and municipal electric utilities. Transmission capability was based on 2,200 MW of on-peak capability

discussed previously and on a loop flow contingency that lowered import capability to 1,500 MW. Consonant with the power flow model, the MARELI runs used 2009 forecast data as a base year.

The results of the modeling are shown as days, or hours, in which supply is insufficient to meet demand. The target is one day in 10 years, which translates into 0.1 day per year. The initial results are based on the availability of native generation alone, assuming no support through transmission from external regions. The preliminary results on a stand-alone basis for 2009 are shown by region in Table 4.

Table 4: LOLP Stand-Alone Basis

Region	LOLP - no support (days/year)
METC	0.02
ITC	14.58
MECS	0.92
ATC zone2	289

This indicates that based upon native generation alone, the 2009 reliability criteria are forecast to be violated in the ITC and ATC Zone regions individually, and for MECS collectively. MISO also reported the loss of load probability results for ITC on a stand alone basis for 2011. According to the reported results, the 2011 stand alone LOLP number increases to 28 days/year for ITC.

The model also incorporates transmission capability and available generation capacity from regions external to Michigan for deficient regions within the state. This is done to determine if reliability constraints can be satisfied by relying on external generation sources. It also identifies how much additional transmission, or native generation, is necessary if reliability criteria cannot be satisfied from existing generation and transmission. Significantly, in these runs, MISO forecasts the availability of generation at the end of the pipe (the other end of the transmission line) and if there is available generation, it makes the generation available through transmission to support the study area. MISO assumes that the transmission itself has 100 percent availability.

Results are available for the three regions within Michigan and for MECS. The amount of external support available depends, in part, on which region is the source of the support. Based upon support from “around the compass,” that is from all external geographical regions running from Mid-Atlantic states to Iowa; the preliminary LOLP numbers for 2009 are shown in Table 5.

Table 5: Preliminary LOLP Numbers with Support from All Geographic Regions

Region	LOLP w/ support (days/year)
METC	0
ITC	0.3
MECS	0.02
ATC-Zone2	N/A

Bearing in mind that the target LOLP is .1 day per year, the preliminary results seem to indicate that the ITC footprint is forecasted to violate the reliability criterion and would require either additional external support, through transmission expansion, or additional native generation. For an integrated ITC/METC region, or MECS, however the 2009 reliability constraints are not violated. This analysis does not consider possible transmission constraints within MECS, it simply compares the amount of generation in the MECS area plus the amount of power that could be imported into MECS and compares that with the amount of load within MECS.

Michigan reliability planning is significantly affected by external energy markets, especially power flows to Ontario and other transmission transactions occurring over the Michigan transmission system. Power flows from regions to Michigan's south and west and into Ontario are increasing, and this has an impact on Michigan's electric transmission capability. For example in the preliminary MARELI run, the angle of the phase shifters between Michigan and Ontario were set to permit 800 MW of flow over the Michigan/Ontario interties. If additional flow occurs over the interties, then flows to Ontario may significantly increase the amount of needed capacity, because transmission available to Michigan decreases as flow to Ontario increases. For example, preliminary results from a scenario in which the phase angle is set to allow a 1,500 MW flow to Ontario results in a forecasted need for an additional 630 MW by MECS 2009.

It is also important to keep in mind that the MARELI results serve reliability purposes only. The model is designed to identify whether additional resources are required, but not the type of resources that most economically meet the need such as peaking, baseload, demand response, or external support. The type of resource that may most appropriately be added depends on the results of the resource expansion model.

The MARELI results indicate whether an area will likely encounter reliability issues for a given forecast of demand. The model assesses the likelihood of meeting forecast demand given the probability that some generating units will be off-line at the time of daily peak demand. However, other unforeseen events also have an impact on a region's electric reliability, such as unusually hot or cold weather, or higher than anticipated economic activity. A more comprehensive assessment of a region's reliability requires that demand growth sensitivities also be tested in the reliability study.

To “stress test” the reliability model, MISO also performed a MARELLI analysis using the high demand growth sensitivity. The 2009 results from the base and high growth sensitivities are shown below in Table 6:

Table 6: 2009 LOLP - Base and High Growth Sensitivities

Region	Base Forecast LOLP days per year	High Forecast LOLP days per year
<i>Assumes no flows to Ontario</i>		
ITC	0.3	1.03
METC	N/A	N/A
MECS	0.02	0.2
<i>Assumes 1,500 MW of flows to Ontario</i>		
ITC	3.46	7.5
METC	0	0
MECS	0.48	1.8

The MARELLI results also included sensitivities for the base, high and low sensitivities, for both the 800 MW and 1,500 MW flows to Ontario. Bearing in mind that the target LOLP is .1, the analysis indicates that additional resources will be required by 2009 to assure an acceptable level of reliability.

Finally, the Plan participants have performed their analysis on a regional basis within Michigan as well as collectively for the Lower Peninsula, as represented by MECS. This recognizes the role of MISO as the regional reliability coordinator with access to network resources throughout the MISO footprint. For example, if network resources are available in the METC footprint to relieve a reliability issue in the ITC footprint, MISO will call upon that METC network resources if needed.

METC does not have the ability to call on independent power producer (IPP) generators that have not been designated as Network Resources. In this study, it was assumed that all IPP generators located in the study area are designated as network resources and are available at no incremental cost to customers.

5. Electric Sales and Peak Demand Forecast

5.1 Introduction

The Demand Team was charged with preparing an annual electric demand and energy forecast for the period 2006 through 2025 for the Plan 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 utility projections were obtained for all investor owned, cooperative and municipal utilities in Michigan. These were compiled and aggregated into the three geographic areas used in the Plan analyses: Southeast Michigan, Balance of Lower Peninsula and Upper Peninsula.

The purpose of the forecast is to provide the Plan with 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 using the MARELI model.

The annual forecast has been prepared for three geographic regions within Michigan, corresponding to electric transmission operating areas. First, Southeast Michigan comprises the area served by ITC. Second, the balance of the Lower Peninsula excluding the Indiana & Michigan Power Company (I&M) service territory¹⁵ is the general area served by the Michigan Joint Zone (including METC), Wolverine Power Supply Cooperative, Inc. (Wolverine) and certain municipal cities of the Michigan Public Power Agency (MPPA). The third area is the Upper Peninsula that is the ATC Z-2 region.

The forecasted electric energy requirements¹⁶ and peak demands are retail energy sales requirements for all electric utilities in each of the three regions. This includes regulated investor owned utilities, regulated electric cooperatives and non-regulated municipal utilities. The forecast covers energy requirements for both bundled full-service and electric choice customers. Excluded from the forecast is electricity generated and consumed on-site by Michigan households and businesses.

Notably, no attempt has been made to determine the allocation of energy requirements and peak demands between regulated utilities and alternative electric suppliers. After the enactment of Public Act 141 of 2000, Michigan electric customers were allowed to select electric generation service from non-regulated, competitive suppliers. According to the Michigan Public Service Commission (MPSC or Commission) Staff's most recent report on electric competition, the load served by alternative electric suppliers was declining throughout the year 2005 and 2006. By the end of the year, Detroit Edison in particular, was experiencing return of choice customers to full bundled service. Moreover, retail choice load generally declined from month to month throughout 2005 for both Detroit Edison and Consumers Energy. Detroit Edison's retail choice

¹⁵ The forecast presented in this report excludes the service area served by PJM Interconnection LLC (a Regional Transmission Organization, that was originally formed to serve Pennsylvania Jersey Maryland in Southwestern Michigan) the area covered by the Michigan jurisdiction of I&M. This includes the municipal utilities of Paw Paw, Dowagiac, South Haven, Niles and Sturgis. Generally, this is about three and one-half percent of total Michigan electricity demand. Therefore, a "Total Michigan" figure, for capacity requirements, renewable potential, or energy efficiency programs would be approximately 3.5 percent higher than the analysis performed with the forecast presented.

¹⁶ The electric energy forecast is for energy requirements, or generation requirements, which is electricity sales plus electric system losses (losses incurred in the transmission and distribution of electricity to retail customers). Electric system losses generally vary from about 7 percent to 10 percent of total generation.

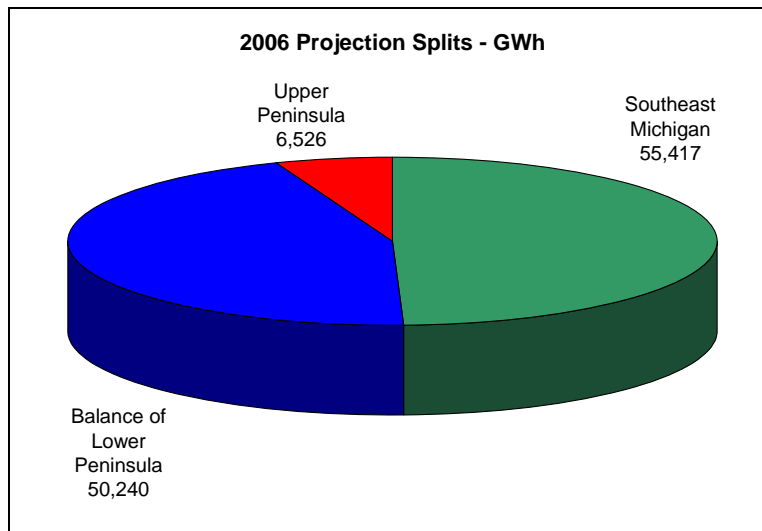
load declined from 2,378 MW in December 2004 to 1,524 MW in December 2005, and Consumers Energy’s retail choice load for the same period declined from 926 MW to 552 MW.

5.2 Generation Requirements and Peak Demand Projection

As noted above, electricity requirements and peak demand projections were aggregated to three geographic regions in the State of Michigan: Southeast Michigan,¹⁷ Balance of Lower Peninsula,¹⁸ and the Upper Peninsula. The relative electricity market size of these regions is shown in Figure 5, depicting forecasted gigawatt-hour¹⁹ (GWh) electric generation requirements by region for the year 2006.

Michigan’s total electric generation requirements are expected 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 are expected to grow 1.2 percent annually, and growth for the balance of the Lower Peninsula is expected to average 1.4 percent. The Upper Peninsula’s annual average growth rate is 0.9 percent for this period. Historical and projected electric generation requirements are shown in Figure 6. Detailed tables of the forecast by state regions, and for the Base, High and low growth scenarios are located in the supplemental tables at the end of this report.

Figure 5: Projection Splits 2006

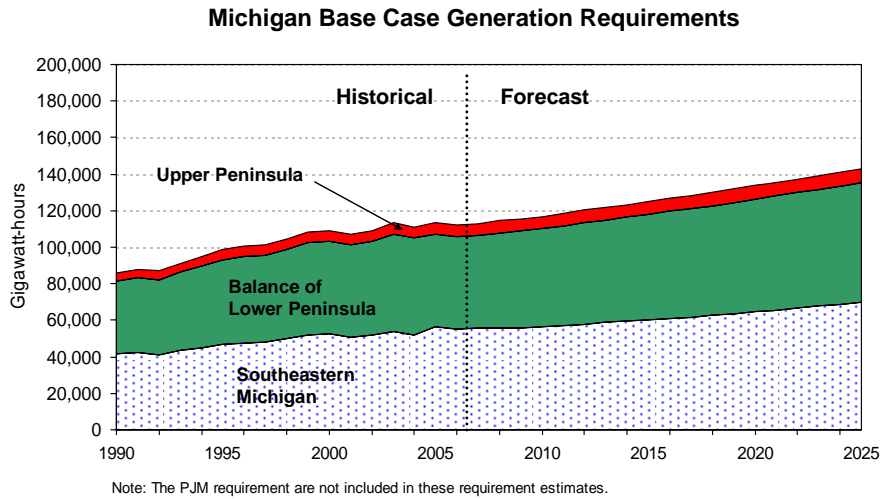


¹⁷ Southeast Michigan is comprised of Detroit Edison, the city of Detroit and the city of Wyandotte.

¹⁸Balance of Lower Peninsula includes all utility electricity deliveries to ultimate customers in the Lower Peninsula excluding both Southeast Michigan and the PJM area of Southwest Michigan.

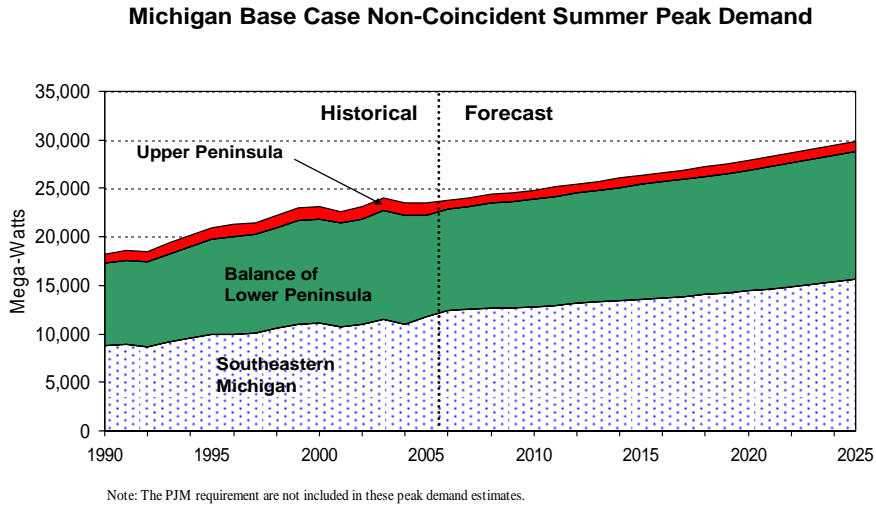
¹⁹ One gigawatt-hour equals one billion watt-hours.

Figure 6: Base Case Generation Requirements, (GWh)



Summer peak electricity demand is expected 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 expected 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. Figure 7 depicts historical and forecasted demand growth:

Figure 7: Base Case Historic and Projected Peak Demand, (MW)



Annual demand forecast tables for each geographic region for each forecast scenario (Base, High and Low Growth) are included in the supplemental tables at the end of this report.

5.3 Comparison with CNF Study Projection

The Plan and the CNF study, which was completed last year, both rely on electricity projections by Michigan utilities. The difference in the current projection is viewed as significant by the

Demand Team, and reflects a lower than expected growth in the Michigan economy and lower growth in the saturation of electric appliances.

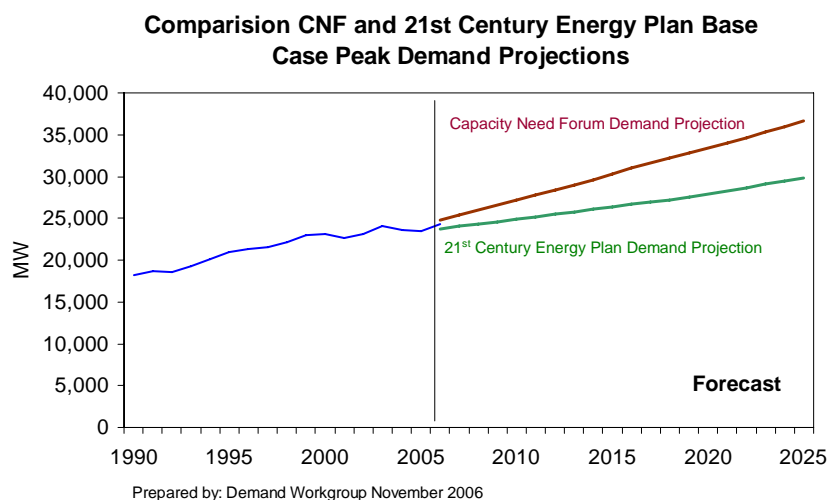
Generally, the Plan outlook as compared to the CNF projection:

1. reflects a revised and lower growth projection by Detroit Edison;
2. reflects a revised and lower growth projection by Consumers Energy; and
3. is relatively unchanged for the remaining Michigan utilities.

Both Detroit Edison and Consumers Energy prepare demand and energy forecasts every six months. Wolverine prepares an annual energy requirements forecast for its members. While the smaller Michigan utilities develop five-year projections for Power Supply Cost Recovery (PSCR) cases for the MPSC, most generally do not project sales and demand at the high level of detail nor with an extended economic projections like that used by Detroit Edison and Consumers Energy.

The Figure 8 compares the CNF Base Case demand projection with the Plan projection for the Base Case. In addition, supplemental tables at the end of this report compare the Base Case scenario energy requirements and summer peak demands for each of the three geographic areas used in the Plan analyses.

Figure 8: Comparison of the CNF Base Case, Plan Base Case Peak Demand, (MW)



Michigan peak demand in the Base Case grows 1.2 percent annually for 2006 through 2025 in the current outlook as compared to 2.1 percent annually in the 2005 CNF study. As one would expect, growth in energy requirements is similarly lower. Energy requirements for 2006 through 2025 grow at 1.3 percent annually in the Plan outlook as compared to 1.8 percent in the CNF study.

5.4 Methodology

The regional forecasts represent composite projections of Michigan's electric utilities. The Plan utility representatives provided electricity requirements and system peak demand projections for each respective utility. These were compiled and aggregated to the appropriate geographic units by MPSC Staff and Wolverine.

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." Indeed, 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 downward the outlook for Michigan's motor vehicle industry, 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.²⁰

5.5 Southeast Michigan

Southeast Michigan's forecast is dominated by the Detroit Edison projection, which accounts for approximately 99 percent of this segment of the forecast. Detroit Edison's forecast was updated in March 2006.

The remainder of the Southeast Michigan area is comprised of the City of Wyandotte and the City of Detroit. Projections for these and all other municipals, except the Lansing Board of Water & Light (BWL), were provided by the Michigan Municipal Electric Association (MMEA) on behalf of the individual municipalities. The municipal electricity projections in the Plan remain relatively unchanged from those used in the CNF study.

Of the Southeast Michigan projections, the Detroit Edison projection method is the most detailed and documented. 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.

The current Detroit Edison forecast as compared to that provided as part of the CNF study shows lower sales growth due to a weaker economic outlook, increased conservation, and efficiency improvements. Sales to the auto industry are especially weak, and decline for the first four years of the forecast due to impacts characterized by Detroit Edison as "massive reorganization plans of local auto makers."

²⁰ This discussion relies on presentations by Detroit Edison and Consumers Energy at the June 22, 2006 21st Century Energy Plan meeting.

5.6 Balance of Lower Peninsula

The forecast of the Balance of Lower Peninsula includes Consumers Energy, Wolverine, municipal utilities and other investor owned utilities. Consumers Energy contributes the majority, about 84 percent, of the Balance of Lower Peninsula load.

Municipal and cooperative projections for the Balance of Lower Peninsula are relatively unchanged from the CNF study. However, Consumers Energy revised its outlook in April 2006 and this new projection is included in this report.

Notably, the Balance of Lower Peninsula excludes municipals and all retail sales in the geographic area within Michigan and covered by AEP. In addition to excluding the AEP jurisdiction, the municipals of Paw Paw, Dowagiac, South Haven, Niles and Sturgis that are contained within the AEP geographic area are excluded. Generally, forecasts for these areas were provided and compiled, but were not intended to be modeled for electric generation resource purposes in this study because this area of Michigan is located in the PJM regional market area.

Consumers Energy's electricity sales and demand forecast is documented in its April 12, 2006 report. The projection of sales is by major economic sector using econometric, linear regression techniques.

Wolverine's forecast was updated in 2005 and is for the period 2006 through 2019. The projected 2006-2019 growth rates (2.8 percent for energy and demand) were applied to the 2019 forecast data to trend the demand and energy forecast through 2025. Wolverine's forecast is developed at the member distribution cooperative level and then aggregated to create a single Wolverine system forecast. The 15 year forecast by Wolverine and its members is updated annually. Wolverine's various forecasts included separate projections for the major economic sectors and are typically based on econometric and trend modeling.

Consumers Energy's 2006 forecast update includes lower expectations for industrial production and employment, and lower housing starts in Michigan. Further, Consumers Energy has reviewed air conditioning saturation data, and believes the saturation for central air conditioning is nearing reasonable limits; air conditioning demand growth is also assumed to be moderated further by the impact of the 2006 implementation of federal efficiency standards for air conditioners.

Similar to Detroit Edison, Consumers Energy's updated outlook for the auto sector is for lower growth due to restructuring in the industry, especially in Michigan. But, unlike the Detroit Edison forecast which shows industrial sales actually declining in the next few years, Consumers Energy's forecast has very slow growth in industrial electricity sales. However, it is significant that Consumers Energy's electricity sales to industrial customers peaked in 1999, at 13,719 GWh, and by 2005 had dropped to 12,429 GWh – due to impacts of the lagging motor vehicle industry in Michigan.

Projections by the municipals are based on historical sales and demand trends of each individual municipality. Additionally, as is the case of all utility forecasts, specific customer information pertaining to future electricity requirements is used to adjust projections for individual retail sales components. The municipal projections were for a 10 year period through 2014, and the growth rate through 2014 (3.3 percent for both energy and demand) was applied to the 2014 forecast data to trend the demand and energy forecasts from 2014 through 2025. BWL reported separately, and its projected growth rate of 2.0 percent per year through 2014 for both energy and demand was used to extend the projection to 2025.

5.7 Upper Peninsula

The Upper Peninsula's forecast is an aggregation of several investor owned utilities and municipal utilities. Three of the five investor owned utilities in the Upper Peninsula are multi-state utilities, which forecast loads on a system-wide basis. These system-wide load forecasts utilize econometric forecasting methods. The investor owned load forecasts for the Upper Peninsula were derived by various allocation methods.

The load forecasts for the remaining two Michigan-only Upper Peninsula investor owned utilities and two municipal electric utilities reflect the use of general historical load growth trends.

The Upper Peninsula's forecast is affected by the operation of two mines in the Upper Peninsula that are served by We Energies. These two mines currently represent 280 MW of total load (20 MW firm, the balance interruptible), which is approximately one-third of the entire Upper Peninsula's forecasted load. Ongoing speculation that the mines could close for various reasons has existed for a number of years. Similarly, discussion of potential increases in mine production and electric load has also taken place. The current forecast provided by We Energies assumes no change in the electrical loads of the mines. Another factor possibly impacting the electric loads in the Upper Peninsula is changing environmental regulations that would cause electric generation units that are operated by paper companies in the Upper Peninsula to be closed. The closing of these paper companies might result in over 100 MW of additional generation being supplied by the existing investor owned or municipal electric utilities.

The composite Upper Peninsula forecasts cover the period 2005 through 2013, 2014 or 2015 depending upon the utility, and average combined growth rates (0.9 percent for energy and demand) were applied to the 2014, 2015 or 2016 end-points to trend the demand and energy forecasts through 2025. The relatively low load growth projected reflects expected continuation of the lower historic growth in both electricity consumption and the related economic growth in the Upper Peninsula as compared to the Lower Peninsula.

5.8 Scenarios for Risk Analysis

For risk analysis, High Growth and Low Growth scenarios were developed. This is done using a formulistic approach, and each of these scenarios is derived from the Base Case, which is the composite of the individual utility forecasts. 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 as for 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 constant 10 percent lowered for years 2015-2025. Thus, the High Growth and Low Growth scenarios are symmetric around the Base Case.

The scenarios are not developed with any probabilistic approach, and the Demand Team did not attempt to assign any judgmental probability to the scenarios.

5.9 Discussion: Risk and Risk Management

The Demand Team recommends that the actual future electricity demand will be higher or lower than the Base Case forecast included in this report. 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 that typically is used for a base forecast.

Errors that can be expected stem from four basic sources. First, the utility forecasts assume some sort of normal weather for both sales and system peak demand projections. Weather can and will vary from the assumed normal, and this will affect annual sales and, even more greatly, system peak demand. 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. So, electricity requirements year to year may be higher or lower than projected due to cyclical impacts.²¹ Third, the trends in economic conditions are difficult to project but remain a 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.

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 this summer, the same forecast used in the Plan report. The Demand Team notes that review of the apparent projection “error” suggests that hotter than normal weather, rather than forecast error, is the likely culprit, and recommends that resource planning efforts should recognize the trending and assumed normal weather aspects of these forecasts.

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 such as the Plan. 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 were achieved this summer and a review of the actual peaks compared to the projections is illustrative.

²¹ The workgroup did not attempt to determine the magnitude of business-cycle impacts on electricity requirements.

Detroit Edison's projected peak for 2006 was 12,577 MW.²² 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 projection uses a peak day average temperature of 83.0 degrees, 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, 3.5 degrees higher than the design temperature for 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 would be 12,588 MW – extremely close to its projection of 12,577 MW.

Consumers Energy's Plan forecasted peak for 2006 is 8,710 MW as compared to its preliminary actual peak of 8,994 MW that occurred on August 1, a difference of 284 MW or 3.3 percent. However, Consumers Energy's forecast is based on a peak day assumed average daily temperature at Lansing's Capital City Airport of 80.5 degrees.²³ The actual Lansing Station high temperature recorded on August 1, 2006, was 94.0 degrees and the low temperature was 78.0 degrees, giving an average of 86.0 degrees, which was 5.5 degrees higher than the forecast in the Base Case. This was the warmest peak day on Consumers Energy's system since 1973, when the average temperature at the Lansing Station was 87.5 degrees.

While the Demand Team has not performed an independent review of these 2006 forecasted versus actual system peaks, the group concludes that 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 error 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 (for projections made recently, and in this report, for the Detroit Edison, Consumers Energy and Wolverine projections), the longer-term forecast is a trend projection that does not intend to capture cyclical economic conditions. The Demand Team recommends that this is not a concern for long-term electricity resource requirements analyses, since these errors tend to be diluted over time.²⁴

The third area of potential error is the assessment of future economic conditions. There is Demand Team consensus that manufacturing output and employment in Michigan, especially in

²² These figures include Wolverine. Detroit Edison's preliminary analysis shows that the peak reached on August 1, 2006 would have actually been higher than on August 2, 2006 if load reductions had not been in effect.

²³ Consumers Energy's forecast method actually is a bit more complex and contains a number of weather related variables, including the square of the average peak day temperature (80.5 squared).

²⁴ The Demand Team does agree that debates do arise regarding whether the source of errors, or source of differences in forecasts, stem from assumed business cycle conditions for near-term projections of one to three years.

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 error is the consumer market for electric appliances. This may be broadly construed to include residential equipment and commercial and industrial equipment. Electricity using, or even electricity substituting,²⁵ equipment and buyer acceptance (market penetration) of the equipment impacts future electricity use. Projecting changes in electricity 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.

6. Expansion Modeling Results

The expansion modeling results are discussed in Chapter 1 of Appendix II.

7. Supplemental Tables: Electric Sales and Peak Demand Forecast

The following pages contain supplemental tables for the electric sales and demand forecast.

²⁵ An example of an electricity substituting appliance is a natural gas fired hot water heater, replacing the need for an electric hot water heater.

**Table 7: Annual Retail System Requirements (GWh): Base Case
(Michigan Statewide, Less PJM, Electric Requirements Projection)**

	Energy (gigawatt-hours)		
	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula
2005	56,859	49,906	6,448
2006	55,417	50,240	6,526
2007	55,606	50,850	6,565
2008	55,967	51,901	6,624
2009	55,839	52,888	6,684
2010	56,454	53,693	6,754
2011	57,130	54,491	6,821
2012	58,003	55,366	6,875
2013	58,718	56,038	6,929
2014	59,569	56,837	6,991
2015	60,304	57,665	7,053
2016	61,073	58,622	7,116
2017	61,830	59,170	7,180
2018	62,780	59,959	7,243
2019	63,717	60,752	7,306
2020	64,674	61,677	7,370
2021	65,647	62,375	7,434
2022	66,635	63,195	7,499
2023	67,641	64,021	7,564
2024	68,662	64,972	7,632
2025	69,701	65,692	7,701

**Table 8: Annual Retail System Requirements (GWh): High Growth
(Michigan Statewide, Less PJM, Electric Requirements Projection)**

	Energy (gigawatt-hours)		
	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula
2005	57,427	50,405	6,513
2006	56,525	51,245	6,657
2007	57,274	52,375	6,762
2008	58,206	53,977	6,889
2009	58,631	55,532	7,018
2010	59,841	56,915	7,160
2011	61,129	58,305	7,299
2012	62,644	59,796	7,425
2013	64,003	61,081	7,552
2014	65,526	62,520	7,690
2015	66,335	63,431	7,759
2016	67,180	64,484	7,828
2017	68,013	65,087	7,897
2018	69,058	65,955	7,967
2019	70,089	66,827	8,037
2020	71,141	67,845	8,107
2021	72,211	68,612	8,178
2022	73,299	69,515	8,249
2023	74,405	70,423	8,321
2024	75,529	71,469	8,395
2025	76,672	72,261	8,471

**Table 9: Annual Retail System Requirements (GWH): Low Growth
(Michigan Statewide, Less PJM, Electric Requirements Projection)**

	Energy (gigawatt-hours)		
	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula
2005	56,290	49,407	6,384
2006	54,308	49,235	6,396
2007	53,938	49,324	6,368
2008	53,728	49,825	6,359
2009	53,047	50,243	6,350
2010	53,067	50,472	6,349
2011	53,131	50,676	6,344
2012	53,363	50,937	6,325
2013	53,434	50,994	6,305
2014	53,612	51,153	6,292
2015	54,274	51,898	6,348
2016	54,966	52,759	6,405
2017	55,647	53,253	6,462
2018	56,502	53,963	6,519
2019	57,346	54,677	6,575
2020	58,207	55,510	6,633
2021	59,082	56,137	6,691
2022	59,972	56,876	6,749
2023	60,876	57,619	6,808
2024	61,796	58,474	6,869
2025	62,731	59,123	6,931

**Table 10: Annual Summer Non-Coincident Peak Demand (MW): Base Case
(Michigan Statewide, Less PJM, Peak Demand Projection)**

	Demand (megawatts)		
	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula
2005	12,209	10,420	898
2006	12,427	10,426	903
2007	12,579	10,578	910
2008	12,682	10,769	918
2009	12,666	10,972	926
2010	12,806	11,107	938
2011	12,955	11,243	946
2012	13,144	11,374	953
2013	13,287	11,511	962
2014	13,442	11,652	971
2015	13,598	11,794	979
2016	13,728	11,939	988
2017	13,865	12,059	997
2018	14,031	12,198	1008
2019	14,190	12,337	1016
2020	14,414	12,476	1025
2021	14,643	12,617	1036
2022	14,875	12,758	1044
2023	15,111	12,900	1054
2024	15,351	13,044	1063
2025	15,595	13,188	1073

Table 11: Annual Summer Non-Coincident Peak Demand (MW): High Growth (Michigan Statewide, Less PJM, Peak Demand Projection)

	Demand (megawatts)		
	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula
2005	12,331	10,524	907
2006	12,676	10,635	921
2007	12,957	10,895	937
2008	13,190	11,199	954
2009	13,300	11,520	972
2010	13,574	11,774	994
2011	13,861	12,030	1,013
2012	14,196	12,284	1,029
2013	14,483	12,547	1,048
2014	14,786	12,817	1,068
2015	14,958	12,973	1,077
2016	15,101	13,133	1,086
2017	15,252	13,265	1,096
2018	15,434	13,418	1,108
2019	15,609	13,571	1,118
2020	15,856	13,724	1,128
2021	16,107	13,878	1,139
2022	16,362	14,034	1,148
2023	16,622	14,190	1,159
2024	16,886	14,348	1,169
2025	17,154	14,507	1,180

**Table 12: Annual Summer Non-Coincident Peak Demand (MW): Low Growth
(Michigan Statewide, Less PJM, Peak Demand Projection)**

	Demand (megawatts)		
	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula
2005	12,087	10,316	889
2006	12,178	10,218	885
2007	12,202	10,261	882
2008	12,175	10,338	881
2009	12,033	10,423	879
2010	12,038	10,441	881
2011	12,048	10,456	880
2012	12,092	10,464	877
2013	12,091	10,475	875
2014	12,098	10,486	874
2015	12,238	10,614	881
2016	12,355	10,745	889
2017	12,479	10,853	897
2018	12,628	10,978	907
2019	12,771	11,104	914
2020	12,973	11,229	923
2021	13,178	11,355	932
2022	13,387	11,482	939
2023	13,600	11,610	948
2024	13,816	11,739	957
2025	14,035	11,870	965

Table 13: Michigan Electricity Sales to Retail Customers, Year 04

Form EIA-861 Data - U.S. Department of Energy, Energy Information, 2006 Administration, July 2006

Sales Type	Type of Entity	Utility Name	Total Sales (MWh)
Ultimate Customer	Utility	Alger-Delta Co-op Electric Assn	59,979
Ultimate Customer	Utility	Alpena Power Co	317,732
Ultimate Customer	Utility	Village of Baraga	18,292
Ultimate Customer	Utility	City of Bay City	307,400
Ultimate Customer	Utility	Bayfield Electric Coop, Inc	193
Ultimate Customer	Utility	City of Charlevoix	64,768
Ultimate Customer	Utility	Village of Chelsea	84,785
Ultimate Customer	Utility	Cherryland Electric Co-op Inc	312,993
Ultimate Customer	Utility	Clinton Village of	24,750
Ultimate Customer	Utility	Cloverland Electric Co-op	204,178
Ultimate Customer	Utility	Coldwater Board of Public Utilities	290,491
Ultimate Customer	Alternative Supplier	CMS Marketing, Serv & Trade Co	1,276,731
Ultimate Customer	Alternative Supplier	Commerce Energy, Inc	762,852
Ultimate Customer	Utility	Consumers Energy Company	33,039,318
Delivery Only	Utility	Consumers Energy Company	4,151,617
Ultimate Customer	Utility	City of Croswell	38,014
Ultimate Customer	Utility	City of Crystal Falls	17,376
Ultimate Customer	Utility	Village of Daggett	1,551
Ultimate Customer	Utility	City of Detroit	538,368
Ultimate Customer	Utility	Detroit Edison Co	39,978,034
Delivery Only	Utility	Detroit Edison Co	9,839,670
Ultimate Customer	Utility	City of Dowagiac	80,013
Ultimate Customer	Alternative Supplier	Dynergy Energy Services Inc	17,884
Ultimate Customer	Utility	City of Eaton Rapids	91,189
Ultimate Customer	Utility	Edison Sault Electric Co	673,049
Ultimate Customer	Alternative Supplier	First Energy Solutions Corp	750,724
Ultimate Customer	Utility	City of Gladstone	33,677
Ultimate Customer	Utility	City of Grand Haven	293,858
Ultimate Customer	Utility	Harbor Springs City of	34,504
Ultimate Customer	Utility	City of Hart Hydro	36,350
Ultimate Customer	Utility	Hillsdale Board of Public Works	144,757
Ultimate Customer	Utility	City of Holland	1,068,824
Ultimate Customer	Utility	Indiana Michigan Power Co	2,973,957
Ultimate Customer	Utility	Village of L'Anse	14,000
Ultimate Customer	Utility	Lansing City of	2,404,953
Ultimate Customer	Utility	City of Lowell	63,433
Ultimate Customer	Utility	City of Marquette	307,582
Ultimate Customer	Utility	City of Marshall	118,131
Ultimate Customer	Alternative Supplier	MidAmerican Energy Co	2,126
Ultimate Customer	Utility	Midwest Energy Cooperative	455,767
Ultimate Customer	Utility	City of Negaunee	23,598
Ultimate Customer	Alternative Supplier	Constellation NewEnergy, Inc	1,987,112
Ultimate Customer	Utility	Newberry Water & Light Board	19,646
Ultimate Customer	Utility	City of Niles	141,012
Ultimate Customer	Utility	Northern States Power Co	135,355
Ultimate Customer	Utility	City of Norway	28,054
Ultimate Customer	Utility	Ontonagon County R E A	27,437
Ultimate Customer	Utility	Village of Paw Paw	41,952
Ultimate Customer	Utility	City of Petoskey	109,955
Ultimate Customer	Utility	City of Portland	34,102
Ultimate Customer	Utility	Presque Isle Elec & Gas Co-op	230,080
Ultimate Customer	Alternative Supplier	Quest Energy LLC	4,043,530

**Table 13: Michigan Electricity Sales to Retail Customers, Year 04
(Continued)**

Ultimate Customer	Alternative Supplier	Sempra Energy Solutions	611,957
Ultimate Customer	Utility	City of Sebewaing	32,509
Ultimate Customer	Utility	City of South Haven	131,659
Ultimate Customer	Utility	City of St Louis	39,224
Ultimate Customer	Utility	City of Stephenson	6,348
Ultimate Customer	Alternative Supplier	Strategic Energy LLC	1,779,720
Ultimate Customer	Utility	City of Sturgis	227,600
Ultimate Customer	Utility	Thumb Electric Co-op of Mich	137,061
Ultimate Customer	Utility	City of Traverse City	312,891
Ultimate Customer	Utility	Tri-County Electric Co-op	269-065
Ultimate Customer	Utility	Village of Union City	14,743
Ultimate Customer	Utility	Upper Peninsula Power Co	761,218
Ultimate Customer	Utility	City of Wakefield	13,339
Ultimate Customer	Utility	Wolverine Power Marketing Co-op	769,399
Ultimate Customer	Utility	Wisconsin Electric Power Co	3,070,726
Ultimate Customer	Utility	Wisconsin Public Service Corp	304,134
Ultimate Customer	Utility	Wyandotte Municipal Serv Comm	264,708
Ultimate Customer	Utility	City of Zeeland	278,493
Ultimate Customer	Alternative Supplier	WPS Energy Services	105,268
Ultimate Customer	Utility	City of Escanaba	154,662
Ultimate Customer	Utility	Great Lakes Energy Co-op	1,185,365
Ultimate Customer	Alternative Supplier	Nordic Marketing LLC	854,047
Ultimate Customer	Alternative Supplier	Mirant Americas Retail Energy	65,544
Ultimate Customer	EIA adjustment	Adjustment 2004	964,393
Ultimate Customer	Utility	EQ-Waste Energy Services Inc	409
Ultimate Customer	Utility	Midland Cogeneration Venture	517,142
Calculated Totals:		A. Total Michigan Retail Sales	106,606,040
		B. Consumers and Edison Choice	13,991,327
		C. Alternative Electric Supplier Total	13,544,036
		D. Difference C-B	-477,291
		E. PJM Portion of SW Michigan	3,596,193
		F. Percent of Michigan	3.37%
		G. Michigan less PJM portion	103,009,847
Notes:			
1. The EIA-861 report is a mandatory reporting of retail electricity sales by all utility and non-utility supplier firms in the U.S.			
2. Total Michigan Retail Sales are the sum of the rows excluding Consumers Energy Company and the Detroit Edison Company (Edison) deliveries to choice customers; these sales are included in the alternative electric supplier sales. Total Consumers and Edison reported deliveries to choice customers is reasonably close to the sum of the reported alternative electric supplier sales			
3. The PJM portion of Southwest Michigan is comprised of the geography within Indiana & Michigan Electric Company (I&M), and includes: I&M; City of Dowagiac; City of Niles; City of Paw Paw; City of Sturgis; and the City of South Haven			
4. The historic EIA Michigan total sales, 1990-2005 were adjusted downward by the above calculated portion of PJM Southwest Michigan area sales. From the derived history of sales, total systems requirements for Michigan (less PJM) are calculated by adding system losses of 7.8 percent. The 7.8 percent loss factor is the Consumers Energy project loss factor; actual losses for SE Michigan would be lower by about a percent and for the UP would be about one percent higher.			
Source: Demand Group Report, 21 st Century Energy Plan, Michigan Public Service Commission			

**Table 14: Comparison of Plan and CNF Study Projection
Annual Summer Non-Coincident Peak Demand (MW)**

Total System Peak Demand			
	21 st Century, 2006	CNF Study, 2005	Difference
2006	23,756	24,765	4.25%
2007	24,067	25,368	5.41%
2008	24,369	25,959	6.52%
2009	24,564	26,544	8.06%
2010	24,851	27,138	9.20%
2011	25,144	27,734	10.30%
2012	25,471	28,344	11.28%
2013	25,760	28,979	12.50%
2014	26,064	29,634	13.70%
2015	26,371	30,299	14.89%
2016	26,655	30,977	16.21%
2017	26,921	31,565	17.25%
2018	27,237	32,171	18.11%
2019	27,543	32,794	19.07%
2020	27,916	33,414	19.70%
2021	28,295	34,040	20.30%
2022	28,676	34,668	20.90%
2023	29,065	35,303	21.46%
2024	29,457	35,943	22.02%
2025	29,856	36,589	22.55%
Source: Demand Workgroup Report, 21 st Century Energy Plan, Michigan Public Service Commission			

**Table 15: Comparison of Plan and CNF Study Projection
Annual Electricity Requirement (GWh)**

Total Annual Energy Requirements			
	21 st Century, 2006	CNF Study, 2005	Difference
2006	112,183	116,648	3.98%
2007	113,021	119,043	5.33%
2008	114,492	121,483	6.11%
2009	115,411	123,640	7.13%
2010	116,902	125,850	7.65%
2011	118,442	128,099	8.15%
2012	120,245	130,486	8.52%
2013	121,685	132,688	9.04%
2014	123,396	135,097	9.48%
2015	125,023	137,529	10.00%
2016	126,811	140,141	10.51%
2017	128,180	142,394	11.09%
2018	129,982	144,843	11.43%
2019	131,775	147,392	11.85%
2020	133,721	149,973	12.15%
2021	135,456	152,588	12.65%
2022	137,329	155,238	13.04%
2023	139,226	157,924	13.43%
2024	141,266	160,649	13.72%
2025	143,094	163,411	14.20%
Source: Demand Workgroup Report, 21 st Century Energy Plan, Michigan Public Service Commission			