MICHIGAN'S

21ST CENTURY ELECTRIC ENERGY PLAN

Appendix – Volume II

Workgroup Reports

SUBMITTED TO

HONORABLE JENNIFER M. GRANHOLM

GOVERNOR OF MICHIGAN

BY

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Introduction to Appendix

On April 6, 2006, Governor Granholm issued Executive Directive 2006-2 initiating the 21st Century Energy Plan (Plan). The Directive requested the Chairman of the Michigan Public Service Commission (MPSC or Commission) to provide by December 31, 2006 a proposed electric energy plan for the State of Michigan, addressing the following eight goals:

1. The state's short-term and long-term electric needs for residential, industrial, commercial, and governmental customers shall be met in an optimum manner that assures a reliable, safe, clean, and affordable supply.
2. The future development of Michigan's electric infrastructure shall further the state's competitive business climate, grow jobs, and provide affordable rates for all customers.
3. The appropriate use and application of energy efficiency, alternative energy technology, and renewable energy technologies shall be consistent with the goal of assuring reliable, safe, clean and affordable energy.
4. This state's natural resources and the environment shall be protected from pollution, physical or visual impairment, or destruction, and future risks associated with fossil fuels shall be mitigated.
5. A renewable portfolio standard shall be created that establishes targets for the share of this state's energy consumption derived from renewable energy sources.
6. New technology options to generate, transmit, or distribute energy more cleanly or more efficiently shall be identified.
7. The state's economic interest in ensuring development of the intellectual capital, financing, infrastructure, and other resources necessary for continued growth of alternative and renewable energy technologies within the state shall be fostered.
8. The plan shall identify any legislative or regulatory changes necessary to its implementation, together with any financial, funding, or incentive mechanisms needed to best position the state to meet the energy challenges of the future.

To assist the Chairman in preparing the Plan, the Commission Staff conducted a collaborative planning process using the same format as the recently completed Capacity Need Forum (CNF). Two courses of action were pursued to address the two major topical areas of the Plan. The first was a major modeling initiative to affirm and update resource modeling from the CNF. The second was development of recommended policy options for meeting the Governor's goals.

The Plan's first meeting was held on April 24, 2006 and attended by over 160 industry stakeholders. Nearly 200 additional participants were added over the course of the following six-month planning process, ultimately representing over 150 organizations including 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; government agencies; electric transmission companies and regional transmission organizations.

Four Workgroups were created to provide information, data, and comments on various aspects of the modeling initiative and the policy review. The four Workgroups were the Capacity Need

Forum (CNF) Update Workgroup, the Energy Efficiency Workgroup, the Renewable Energy Workgroup, and the Alternative Technologies Workgroup. Workgroups began meeting in earnest in early May and continued through the summer.

Throughout the planning process, Staff sought input and feedback from industry experts and participants. During June and July, strawman policy proposals from each workgroup were drafted and several opportunities for comment were provided. The first comment period was limited to the specific workgroup members, but in early August, the strawman policy proposals were packaged together and comments sought from all Plan participants. In addition to several public meetings, Staff also conducted one-on-one colloquies with participants to discuss policy issues. Over 35 such meetings with Staff were conducted during September, October, and November.

The final documents prepared by MPSC Staff and transmitted to J. Peter Lark, Chairman of the Michigan Public Service Commission are bound in Appendices I and II.

Appendix Volume I contains an overview of resource modeling conducted for the Plan, policy reports that identify the barriers to developing and securing electric resource and generating assets necessary for Michigan’s future, and recommended legislation.

Appendix Volume II, details the results of the quantitative analysis (modeling), assesses Michigan’s future electric capacity needs, identifies resource options available to the state and its ratepayers, and proposes a general plan to meet the future electric capacity and energy needs. Appendix Volume II, Chapter 1, contains a discussion of the scenarios and sensitivities that were analyzed, the model results, and the assumptions and model inputs, including emission allowance cost and fuel price forecasts. Appendix Volume II, Chapters 2 through 5, are resource assessment reports prepared for each of the four 21st Century Energy Plan Workgroups and drafted by the respective Workgroup chairs. They report on the data used in the modeling program and also analyze operational issues, planning principles, scenario development, and policy development.

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Copies of the 21st Century Electric Energy Plan, and Appendices I and II are available on the Michigan Public Service Commission's website at: http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm.

CHAPTER 1

Michigan Integrated Resource Plan Report

1. Executive Summary

The 21st Century Energy Plan (Plan) was created as a collaborative industry-wide process to assess the projected need for electrical generating capacity in Michigan over the near and long-term future and to provide recommendations on the state's electric energy policy. The CNF Update Workgroup was responsible for modeling the state's electric generation resource needs and scenario development. The Workgroup combined the demand forecast with the inventory of existing resources to determine the timing and characteristics of future capacity need. In addition, the Workgroup developed a set of scenarios likely to have a significant impact on the modeling results and provided an assessment of the scenarios. NewEnergy Associates was retained to perform the data development and modeling.

The purpose of NewEnergy Associates integrated resource plan (IRP) modeling was to evaluate a broad range of resource options across a number of market scenarios to determine the amounts and types of capacity that best fit Michigan's needs from a reliability and economic perspective. This study was designed to be comprehensive, by evaluating a wide-ranging set of in-state resources and fully modeling economy energy markets within the eastern interconnection.

The IRP assessment exhibited a number of key resource planning results. Reliability analyses indicate that Michigan is in need of near-term capacity to meet planning reserve criteria. This need is demonstrated by the model's adoption of three combustion turbines, as soon as practical, in 2008. After the model added sufficient capacity for reliability, the model adopted baseload capacity for the state. The expansion plan selected energy producing baseload resources as soon as the construction schedule permits. Baseload coal units, when they became available in 2012, were the preferred resource. Throughout the remaining study horizon, coal continued to be the preferred resource for Michigan. The near-term need for immediate capacity to meet planning reserve criteria and the need for baseload energy was further underscored in a variety of sensitivities and scenarios. Emissions standards represent a major contingency that can be managed by use of energy efficiency and renewable energy options.

2. Introduction

2.1 Purpose of the Integrated Resource Plan

The purpose of this integrated resource IRP analysis modeling was to evaluate a broad range of resource options across a number of market scenarios to determine the amounts and types of capacity that best fit Michigan's needs from a reliability and economic perspective. This study was designed to be comprehensive, by evaluating a wide-ranging set of in-state generation, energy efficiency, and transmission resources and fully modeling economy energy markets within the eastern interconnect.

2.2 Overview of Integrated Resource Plan Process

Step 1 – Review Planning Policies and Develop Key Assumptions

- Identify and review planning policies for the Plan, including reliability criteria and other operational constraints and performance-measuring planning objectives.

- Develop a Base Case forecast of projections for key system level assumptions such as:
  - Load growth
  - Discount and inflation rates
  - Fuel prices
  - Emission allowance prices

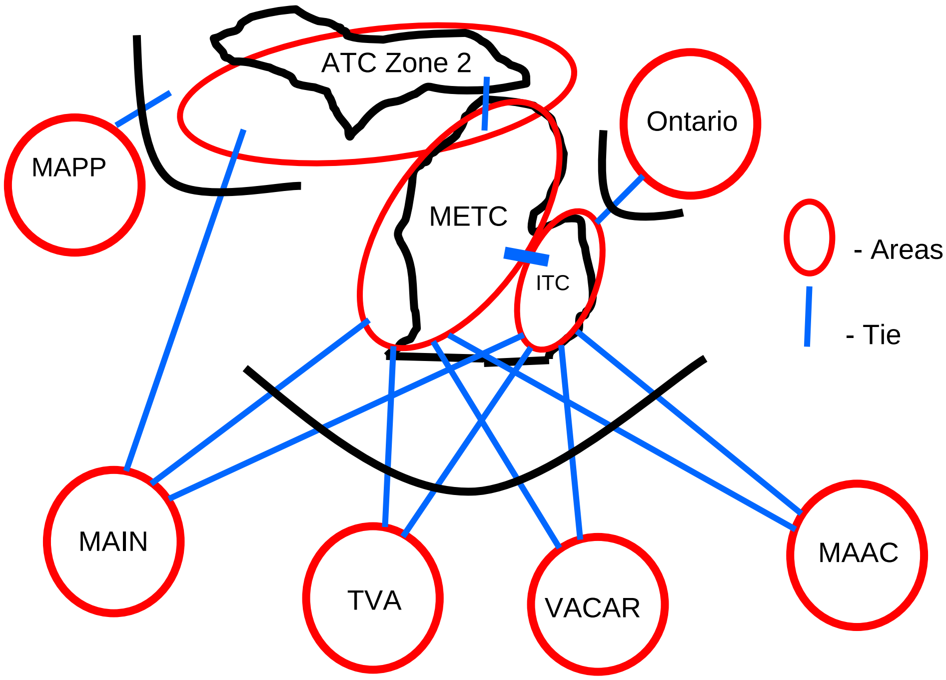
- Identify sources of uncertainty and define and develop future scenarios to capture the range of potential variations in such uncertainties.

The study was undertaken on a regional basis within Michigan. The regions coincide with the service territories of the International Transmission Company (ITC), the Michigan Electric Transmission Company (METC), and the American Transmission Company (ATC) zone 2. In addition to three distinct regions, reliability and transmission modeling included ITC and METC collectively, referred to as the Michigan Electric Coordinated System (MECS).[1] Economy energy was sourced from five regions within the U.S. Because of Ontario's policy initiative to decommission all of its coal-based generation, Ontario was not considered as a source of economy energy. These regions are shown in Figure 1 on the following page.

Comprehensive resource planning on a regional basis requires sophisticated representations of loads and of the generation and transmission systems that supply the load. While the loads and individual generating units can be readily modeled, individual transmission line representations are beyond the analytical capabilities of optimizing, multi-area, resource-planning computer models. Instead, the key aspects of the transmission system are captured in the model using transmission interfaces to represent the transmission interconnection(s) between adjacent zones. The zonal/interface representation of the Michigan system in Figure 1 shows the key transmission constraints affecting the Michigan transmission system.

[1] Although ITC and METC have recently merged, the use of these three regions continues to reflect historic electric power transfer limits between the regions.

Figure 1: Michigan System Representation



Much of the data collected for the 2005 Capacity Needs Forum was determined to be current and appropriate to use for the Plan. This included the following types of existing and proposed resources:

- Supply-side resources
    - Existing generation units
    - Estimated retirements
    - Optional new supporting technologies

- Transmission interfaces
    - Existing capabilities
    - Optional enhancements

The data items compiled for each of the resource types include:

- Load representations
    - Forecast annual energy and peak demand growth
    - Consumption patterns: monthly peaks, energy, and hourly shapes

- Supply-side resource representations
    - Capital cost
    - Construction lead time, annual capital expenditure profile
    - Financing charges (e.g. levelized carrying charge rates)

    - Annual fixed operations and maintenance (O&M) expenses
    - Annual capitalized O&M expenditures
    - Variable O&M expenses
    - Book and operating lives
    - Maximum and minimum net capacities
    - Seasonal capacity de-rates
    - Monthly maximum energy limits
    - Fuel type(s) and any fuel-related limitation(s)
    - Plant-specific fuel price projections
    - Net heat rate curves
    - Annual planned maintenance requirements
    - Full and partial forced outage rates
    - Dispatchability/must-run constraints
    - Effluent and emissions rates

- Demand side resource representations
    - Annual energy savings
    - Utility administrative and program costs (fixed and/or per participant)
    - On-peak capacity savings

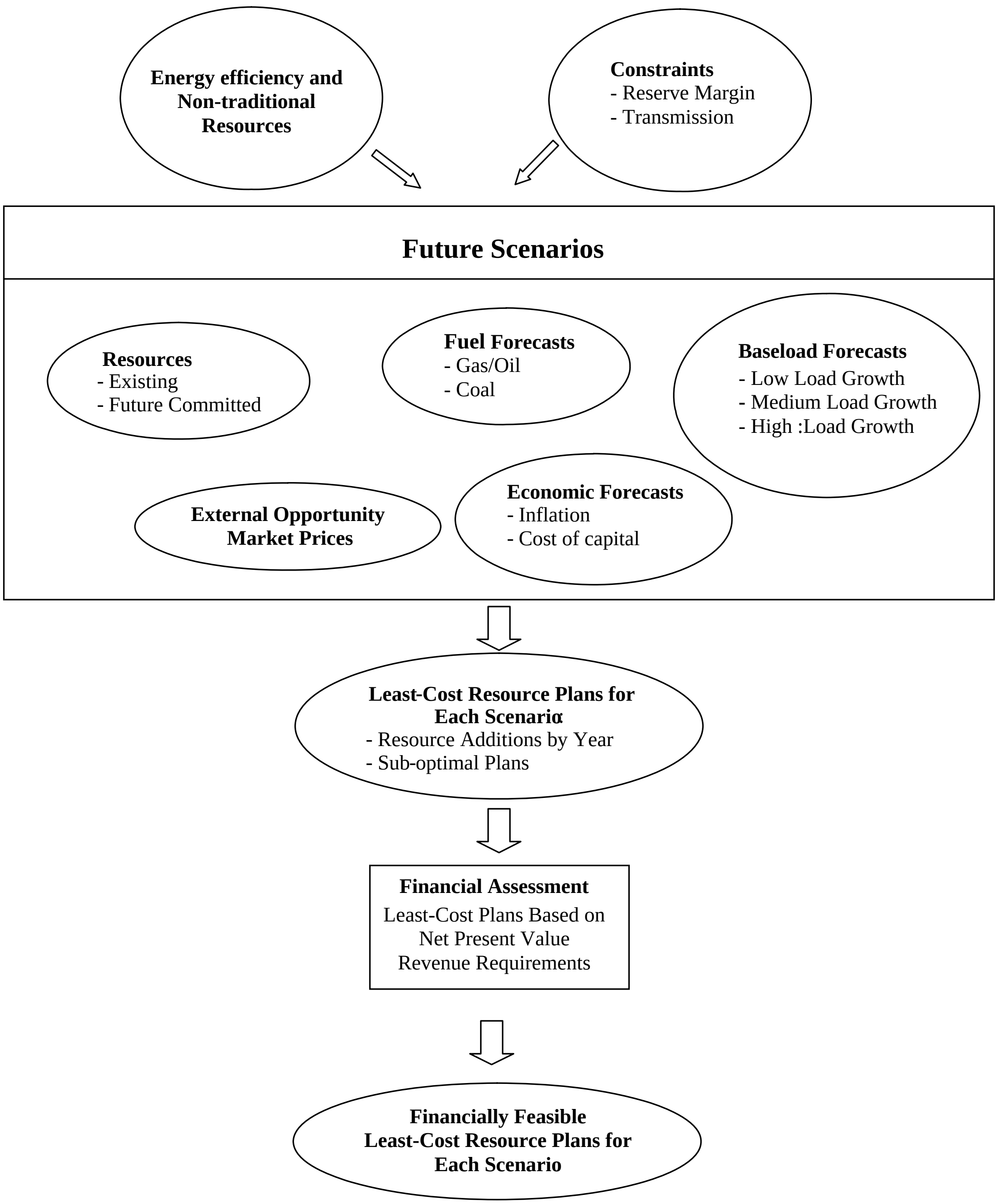
- Transmission interface representations
    - Bi-directional megawatt (MW) capabilities

In addition, the following system-level policies and assumptions were adopted:

- Performance measure(s), for example net present value (NPV) utility cost
- Planning period
- Inflation rates
- Discount rates
- Fuel price escalation rates
- Construction cost escalation rates
- System installed capacity reserve requirement
- Zonal installed capacity reserve requirement
- Emissions constraints
- Sensitivity analysis criteria
- Emissions allowance prices

Step 2 – Optimize Michigan's Supply-Side Portfolio (Including new Demand Side Resources):

Figure 2: Optimization Process



Step 3 – Plan Integration:

- Screen all available future resource types on a full life-cycle, present value levelized, \$/MWh bus-bar cost over a range of potential capacity factors.
- Eliminate from consideration, resources that are unable to compete economically over the study horizon.
- Schedule in all alternative generation (i.e., wind, landfill gas, anaerobic digestion, and combined heat and power) and demand side alternatives.
- Identify robust supply-side resources (resources selected under most scenarios).
- Identify resources which require near-term capital commitments.
- Achieve and maintain near-term reliability while attempting to meet a long-term 15 percent reserve margin.
- Identify key near-term resource contingencies for the optional plans, based upon quantifiable and subjective criteria:
  - Fuel diversification
  - Flexibility
  - Others

3. Planning Process

3.1 Planning Tools

The Integration Team relied on software developed by NewEnergy Associates, LLC (NewEnergy), to model electric generation resource needs. NewEnergy has developed several proprietary planning models to assist with electric capacity planning. These models are comprehensive, allowing comparisons of demand side measures along with Central Station and non-Central Station generation options. The "Strategist" model uses a dynamic programming algorithm to search for and select an optimum resource solution, when additional resources are needed. The modeling procedures allow for a comparison, or ranking, among solutions as scenarios change. This option allows planners to manage cost and risk associated with the various scenarios.

The Net Economy Interchange module uses a marginal cost algorithm to estimate economy energy prices among interconnected systems, while respecting transfer limits between adjacent systems. The module encompasses a broad geographical footprint comprising most of the utilities and generating units in the U.S. eastern interconnected system.

The principal objective of the model is to identify the best resource plan that will satisfy the electric generation needs of the state, subject to a reliability-based generation reserve constraint. A more detailed description of the model is provided in Section 7.

4. Modeling Requirements for Generation Resources

4.1. Existing System

4.1.1 Existing Central Station Generation Resources

All existing generation was reviewed in the CNF project by Consumers Energy, Detroit Edison, Wolverine Power Supply Cooperative, and Lansing Board of Water and Light (BWL). Plan participants agreed that the CNF data remained accurate and was appropriate for use in this modeling initiative. Existing resources consisted 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 existing resources are listed in Section 6, and summarized in Figure 3 through Figure 6.

Figure 3: ITC Existing Capacity Mix

- ITC Area (see Table 20, p. 43)

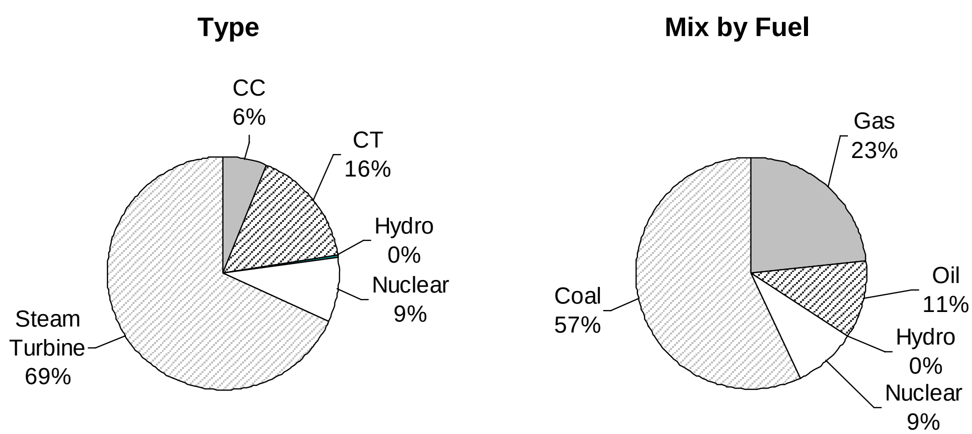


Figure 4: METC Existing Capacity Mix

- METC Area (see Table 21, p. 46)

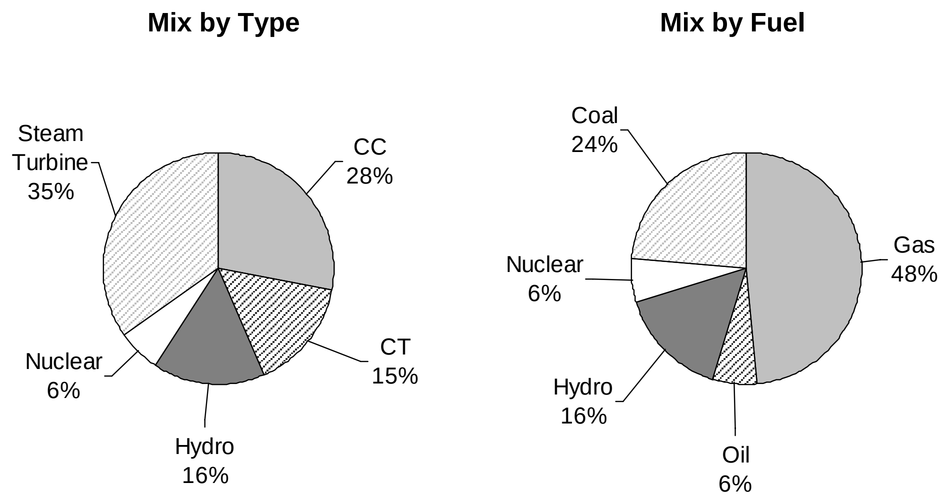


Figure 5: Wolverine Existing Capacity Mix

- Wolverine (see Table 22, p. 51)

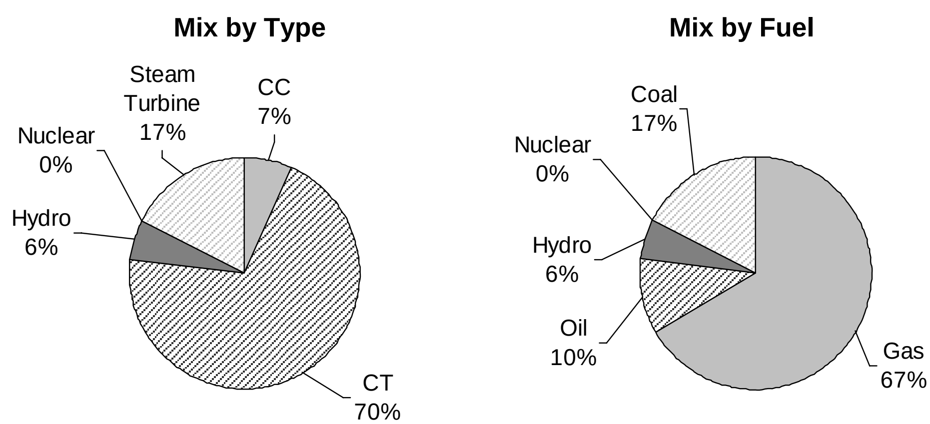
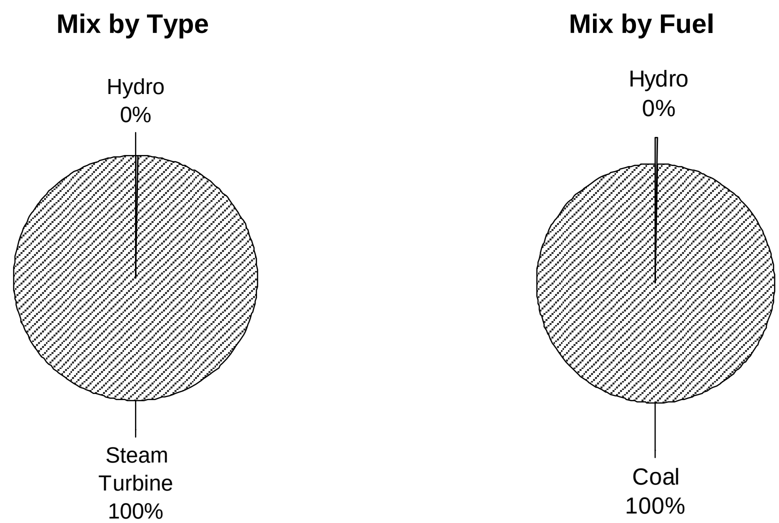


Figure 6: Lansing Board of Water & Light Existing Capacity Mix

- Lansing BWL (see Table 23, p.51)



4.1.2 Existing Non-Central Station Generation Resources

All non-Central Station generation was reviewed by Consumers, Detroit Edison, Wolverine, and the Lansing Board of Water and Light. Plan participants concluded that this data was accurate and reasonable for this modeling initiative. Non-Central Station resources consist of landfill gas, biomass, anaerobic digestion, other steam turbines, and wind. The existing resources are listed in Section 6, and summarized in Figure 7 and Figure 8.

Figure 7: ITC Non-Central Station Mix

- ITC Area (see Table 20, p. 43)

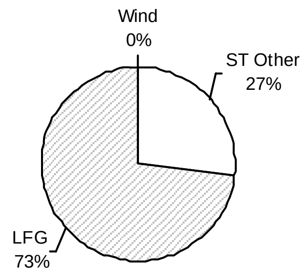
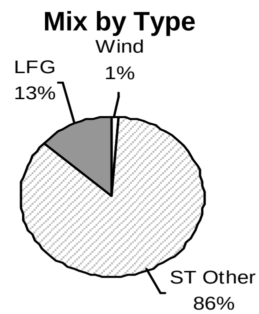


Figure 8: METC Non-Central Station Generation Mix

- METC Area (see Table 21, p. 46)



- Wolverine (see Table 22)
    - No Non-Central Station Generation
- Lansing BWL (see Table 23)
    - No Non-Central Station Generation

The CNF Update Workgroup provided the following assumptions 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.

The detailed schedule of unit retirements is shown in Table 24 (p. 52). Table 1 summarizes the total capacity retirements each year, through the course of the study horizon.

Table 1: 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

4.1.3 Existing Demand Side Resources

No existing demand side resources are assumed to be operational.

4.1.4 Existing Transmission Resources

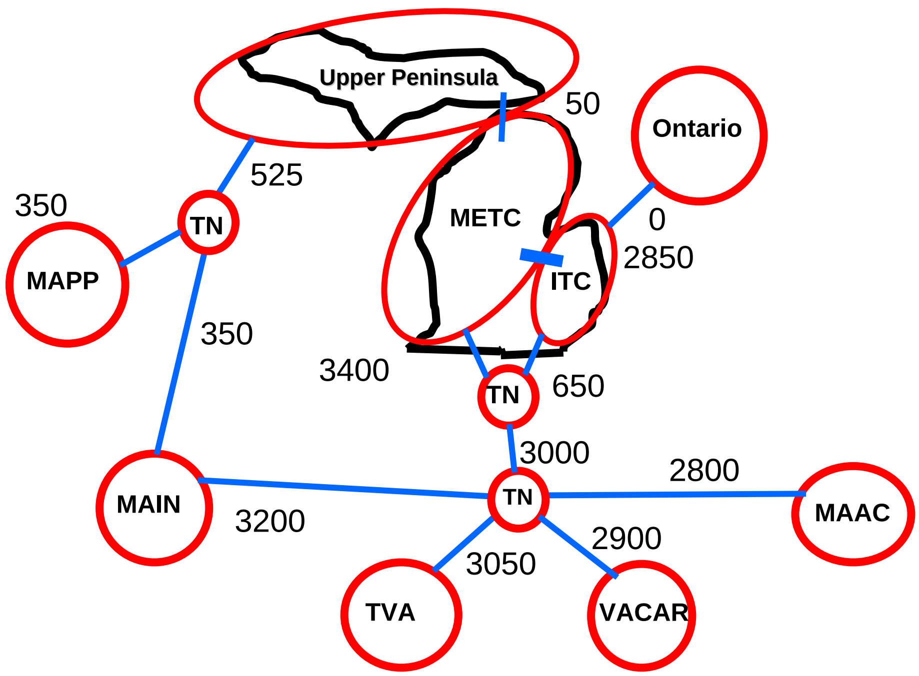
The Transmission and Distribution Workgroup from the 2005 Capacity Needs Forum was responsible for estimating the transmission import capability into Michigan. The Workgroup's specific responsibilities included:

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 upgrades that may be available to increase transmission transfer capability within Michigan and into Michigan; and
3. reviewing issues that may have an impact on the state's ability to utilize or expand its transmission system.

The Figure 9 represents the results of the Transmission and Distribution Workgroup's estimation of import capability. These assumptions were augmented with import capabilities for the Upper

Peninsula, provided by ATC.[2] 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, 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.

Figure 9: Transmission Interface Capability in 2009 (in MW)



Interface	Capacity (MW)	ST[1] From	ST To
All to MECS	3000	TN[2] Hub	Michigan
Into METC	3400	TN Hub	METC
METC to ITC	2850	METC	ITC
Into ITC	650	TN Hub	ITC
Into Ontario	0	ITC	Ontario
Notes: [1] ST refers to Strategist. [2] TN refers to transfer node.			

[2] August 4, 2005 conference call with Jay Porter of ATC.

4.2 Resource Options

4.2.1 Options Overview

The CNF Update Workgroup selected the base technologies for Central Station utility generation options. The generation options include:

- Pulverized coal (super-critical, sub-critical and ultra super-critical)
- Circulating fluidized-bed boilers (CFB)
- Nuclear
- Integrated gasification combined cycle (IGCC)
- Natural gas combined cycle combustion turbines
- Simple cycle combustion turbines.

For pulverized coal it was assumed that new source environmental compliance would require selective catalytic reduction (SCR) for NOx removal, a scrubber for SO_2 removal, a fabric filter or precipitator for particulate control and some type of sorbent injection for removal of mercury. While the Workgroup included ultra super-critical in its inventory of production technology options, this technology was not used in the modeling phase of this study. The generation options emissions assumptions are shown in Table 2.

4.2.2 Generation Options

The Table 2 summarizes the CNF Update Workgroup's estimate of costs for the generation options. All dollar figures are represented in 2006 real dollars.

Table 2: Generation Options Emissions Assumptions

Plant Type	SO_2 (lbs./MMBtu)	NOx (lbs./MMBtu)	Hg (lbs./MMBtu)	CO_2 (lbs./MMBtu)
Pulverized Coal Sub-Critical	0.05	0.08	1.22×10^{-6}	201
Pulverized Coal Super-Critical	0.05	0.08	1.22×10^{-6}	201
Fluidized Bed	0.02	0.10	1.22×10^{-6}	200
IGCC	0.03	0.06	8.05×10^{-7}	195
Nuclear	0	0	0	0
Natural Gas Combined Cycle	.001	0.03	0	120
Natural Gas Combustion Turbines	.001	0.03	0	120
Note: MMBtu – million British Thermal Unit (BTU)				

The Workgroup assumed that new coal fired generation would burn Powder River Basin (PRB) coal. The only exception was a new IGCC unit which was priced with either eastern or PRB coal. Table 3 summarizes the CNF Update Workgroup's estimate of emissions for the generation options.

4.2.3 Other Assumptions

To more accurately represent the expected operating costs of natural gas combined cycle generation, $20.18/kW (2006$) was added to the plant's annual fixed O&M expenses, to represent the cost of reserving annual pipeline capacity. Pipeline capacity is needed to support the transmission of gas from Louisiana to Michigan. For natural gas combustion turbines, $5.12/kW (2006$) was added to the annual fixed O&M for the summer months to support the transmission of gas from Louisiana to Michigan.

The sources of the natural gas firm transportation rates were the currently effective tariff rates for ANR pipeline (Tariff FTS-1) and Trunkline Gas Company (Tariff FT). The final fixed price adder was the result of a straight average between the two pipeline tariffs. In addition, a commodity charge of $0.014/MMBtu[3] was added to the commodity price for gas delivered under the reserved pipeline capacity.

All future generation options include a transmission interconnection cost based on 5 percent of the capital investment for a generic coal unit ($77.56/kW, 2006$).

4.2.4 Renewable Options

The CNF Update, Renewable Energy, and Alternative Energy Technologies Workgroups were responsible for compiling an inventory of existing renewable energy, distributed generators, combined heat and power (CHP), and other generation resources in Michigan. These groups were also responsible for identifying and compiling data on new renewable, distributed generators, CHP, and new, innovative electric generating options that are likely to be available to meet Michigan's electric generating capacity needs. The Renewable Energy Workgroup provided estimates for the capacity potential for renewable resources, investment costs, operating costs, and operating characteristics. Renewable options considered for this study include: landfill gas, anaerobic digestion, cellulosic biomass, combined heat and power, and wind.

The Table 4 outlines the schedule of cumulative estimated available new nameplate capacity (MW) by renewable resource type used in the model.

[3] 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 (kWh) (3,412 BTUs = 1 kWh).

Table 3: Generation Options Cost Table

Type	Capacity (MW)	Construction Cost ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Assumed First Year Available
Pulverized Coal Sub-critical	500	1,478	42.26	1.86	9,496	2012
Pulverized Coal Super-critical	500	1,551	44.91	1.75	8,861	2012
Pulverized Coal Ultra super-critical	500	1675	47.16	1.84	8000	2012
Fluidized Bed	300	1.628	46.11	4.37	9,996	2012
UP CFB	150	1.766	46.11	4.37	9,996	2012
IGCC	550	1,785	61.30	0.98	9,000	2012
IGCC-PRB	550	1,999	61.30	0.98	10,080	2012
Nuclear	1,000	2,352	70.04	0.55	10,400	2018
Natural Gas , CC	500	599	5.57	2.19	7,200	2009
Natural Gas , CT	160	425	2.19	3.83	10,450	2008

Table 4: Modeled Renewable Capacity (Cumulative New Generation in MW)

Year	Landfill Gas	Anaerobic Digestion	Cellulosic Biomass	Combined Heat & Power	Wind
2006	0	0	0	0	0
2007	24	4	0	36	10
2008	47	11	41	71	87
2009	71	18	81	107	88
2010	94	24	122	143	119
2011	118	30	162	178	154
2012	120	43	207	178	272
2013	123	53	251	178	360
2014	126	64	296	178	410
2015	128	73	340	178	465
2016	131	82	385	178	525
2017	134	83	392	178	535
2018	136	85	401	178	546
2019	139	87	410	178	559
2020	142	89	419	178	571
2021	145	91	428	178	583
2022	147	93	437	178	595
2023	150	95	446	178	609
2024	153	97	456	178	622
2025	155	99	465	178	634
Values shown are nameplate capacity.					

Table 5 outlines the capacity factor and cost assumptions for the renewable resources that were modeled.

Table 5: Capacity Factor and Cost Assumptions for Renewable Resources Modeled

	Capacity (%)	Cost (¢/kWh)
Landfill gas	90	7.4
Wind	28	7.4
CHP	90	7.9
Anaerobic digesters	80	8.2
Cellulosic biomass	80	6.9

All non-Central Station resources were modeled as purchase power agreements and the generators were paid 7¢/kWh (2005$) and then escalated annually at the GDP deflator escalation rate. As an alternative, for modeling in certain scenarios, the cost of renewable energy options was also included as a fixed-price, long-term contract with no escalation adjustments. Wind was assumed to have zero emissions. Cellulosic biomass was considered to be greenhouse gas neutral, and cogeneration, landfill gas, and anaerobic digestion emissions were assumed to result in zero net emissions.

4.2.5 Demand Side Options

The estimated potential impacts of energy efficiency programs were represented as a resource in the Energy Efficiency Scenarios. Table 6 represents the annual cumulative capacity and energy savings associated with the base energy efficiency program. These MW and gigawatt hour (GWh) savings include approximately 570 MW of new load management program impacts. In addition, a sensitivity on the energy efficiency was performed to represent more conservative estimates of achievable energy efficiency combined with higher program costs.

Table 6: Modeled Energy Efficiency Program Cost and Impacts

	Base Case Energy Efficiency			Reduced Penetration Energy Efficiency		
Year	Cost ($000')	Capacity[1] (MW)	Energy (GWh)	Cost ($000)	Capacity[1] (MW)	Energy (GWh)
2007	129,390	385	675	151,390	349	388
2008	130,247	513	1,334	152,247	442	760
2009	131,077	640	1,992	153,077	532	1,132
2010	131,880	764	2,651	153,880	620	1,504
2011	132,661	886	3,309	154,661	706	1,875
2012	197,022	1,069	4,349	217,222	814	2,498
2013	197,764	1,250	5,389	217,964	919	3,120
2014	198,489	1,429	6,429	218,689	1,023	3,742
2015	199,200	1,609	7,469	219,400	1,127	4,364
2016	199,897	1,787	8,509	220,097	1,229	4,987
2017	136,982	1,902	9,167	158,982	1,309	5,358
2018	137,656	2,016	9,825	159,656	1,387	5,729
2019	138,320	2,130	10,483	160,320	1,464	6,100
2020	138,975	2,243	11,141	160,975	1,541	6,471
2021	139,623	2,356	11,798	161,623	1,619	6,842
2022	140,263	2,468	12,456	162,263	1,695	7,213
2023	140,897	2,579	13,114	162,897	1,770	7,585
2024	141,525	2,690	13,772	163,525	1,844	7,956
2025	142,148	2,801	14,430	164,148	1,920	8,327

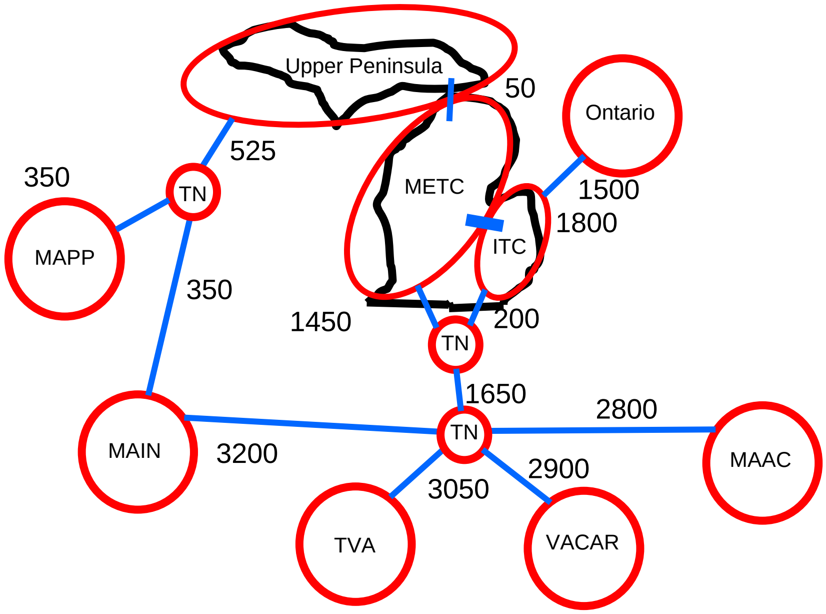
Note: [1] Includes 570 MW of new load management by 2015

4.2.6 Transmission Options

For the purpose of the Michigan IRP modeling, external capacity selling into or purchasing from the Michigan market was excluded. The external market was utilized to represent only non-firm 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 1,500 MW of sales utilizing Michigan transmission to transfer power from MISO to Ontario Hydro. Figure 10 represents transfer capabilities modeled for the Low Import case.

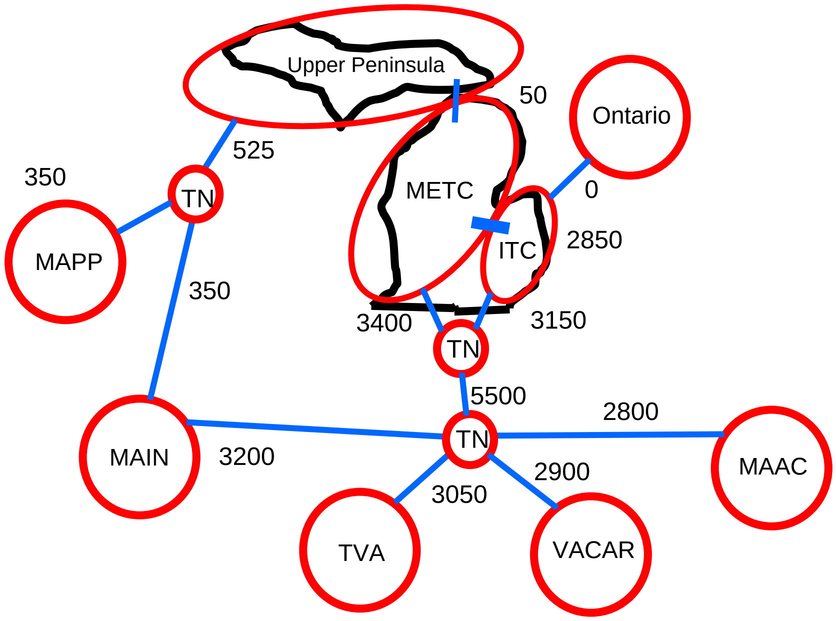
Figure 10: Low Estimate of Transmission Import Capabilities in 2009 (in MW)



Interface	Capacity (MW)	ST From	ST To
All to MECS	1650	TN Hub	Michigan
Into METC	1450	TN Hub	METC
METC to ITC	1800	METC	ITC
Into ITC	200	TN Hub	ITC
Into Ontario	1500	ITC	Ontario
Notes: TN refers to transfer node and ST refers to Strategist.			

The Expanded Transmission case assumed an additional 2,500 MW of transfer capability from the South into ITC with an option capital cost of $800 million, of which $640 million was assumed to be paid by Michigan. The remaining $160 million was assumed to be paid by all transmission users in the rest of the MISO footprint. Figure 11 represents the impact of this 2,500 MW expansion transfer capability.

Figure 11: Expanded Estimate of Transmission Import Capability in 2009 (in MW)



Interface	Capacity (MW)	ST From	ST To
All to MECS	5500	TN Hub	Michigan
Into METC	3400	TN Hub	METC
METC to ITC	2850	METC	ITC
Into ITC	3150	TN Hub	ITC
Into Ontario	0	ITC	Ontario
Notes: TN refers to transfer node and ST refers to Strategist.			

The estimated 2009 transfer capabilities into Michigan's Lower Peninsula under the base, high import, and low import cases are shown in Table 7:

Table 7: Key Interface Capabilities

	Base Case (MW)	Expanded (MW)	Low Import (MW)
Into Michigan	3,000	5,500	1,650
Into METC	3,400	3,400	1,450
Into ITC	650	3,150	200
METC/ITC	2,850	2,850	1,800

4.3 Additional Assumptions

4.3.1 System Reserve Margin Requirements

For the purpose of this study, 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. Interchange with the external market represented non-firm spot market purchases and sales of energy only. As indicated previously, no attempt was made to simultaneously include external capacity and economy energy markets.

For the Expanded Transmission sensitivity, the reserve margin requirement for the state was lowered to 12 percent. This reflects the reliability benefit that would be expected to result from the additional transfer capability into the state.

4.3.2 Demand Forecast

The CNF Update Workgroup was charged with preparing a base electric demand and energy forecast for the period running from 2006 to 2025 for use in modeling for the Plan. The projections rely primarily on forecast data provided by members of the Workgroup including: Consumers Energy, Detroit Edison, Wolverine Power Supply Cooperative, Michigan municipal utilities, We Energies, and Wisconsin Public Service. Due to the uncertainties in forecasting electric demand, forecast sensitivities were also developed by the Workgroup to represent low load growth and high load growth assumptions.

Michigan's total electricity needs from 2006 to 2025 are expected to grow from 112,183 to 143,094 GWh (27.6% cumulative, or about 1.3% per year). Over the same time period, peak demand is expected to grow from 23,756 to 29,856 MW (25.7% cumulative, or about 1.2% per year).

4.3.3 Fuel Forecast

Coal Price Forecast

Delivered coal forecasts were generated for 10 of the 13 EIA-defined coal demand regions (see Figure 12). These forecasts were sourced from four of the 14 EIA-defined coal supply regions shown in Figure 13.

Figure 12: Coal Demand Regions

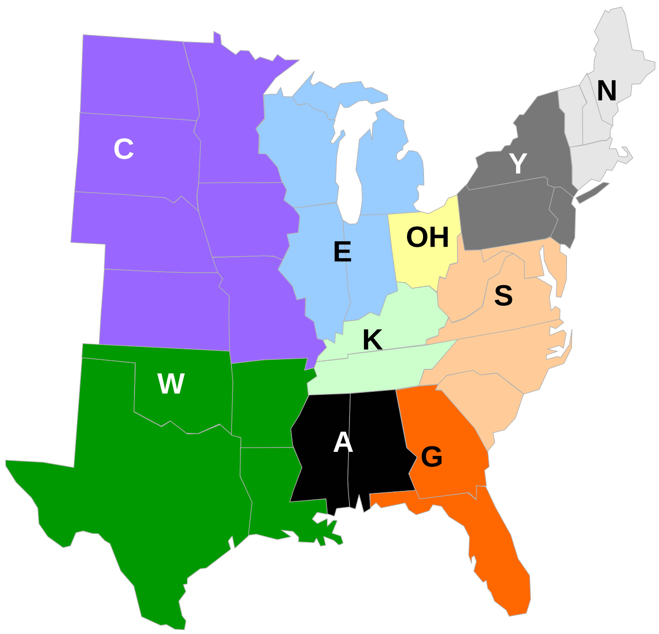
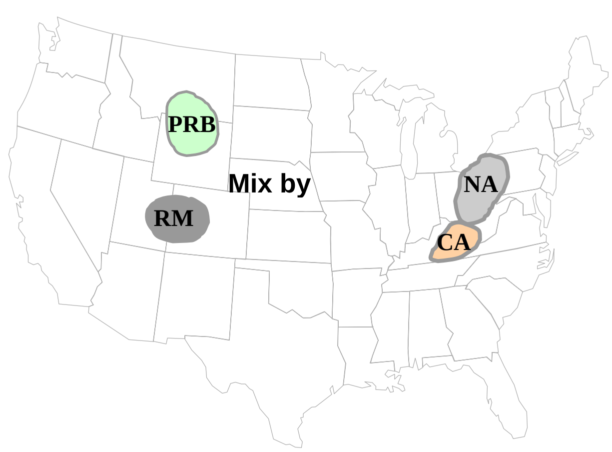


Figure 13: Coal Supply Regions



The average transportation cost between each supply and demand region was obtained from the EIA 2006 Annual Energy Outlook. Additionally, an annual transportation cost escalation rate of 2 percent was adopted, which is the rate from the EIA 2006 Annual Energy Outlook. Table 8 enumerates the transportation charges between each of the supply regions and the "EN" region, where Michigan is based.

Table 8: Estimated Coal Transportation Costs

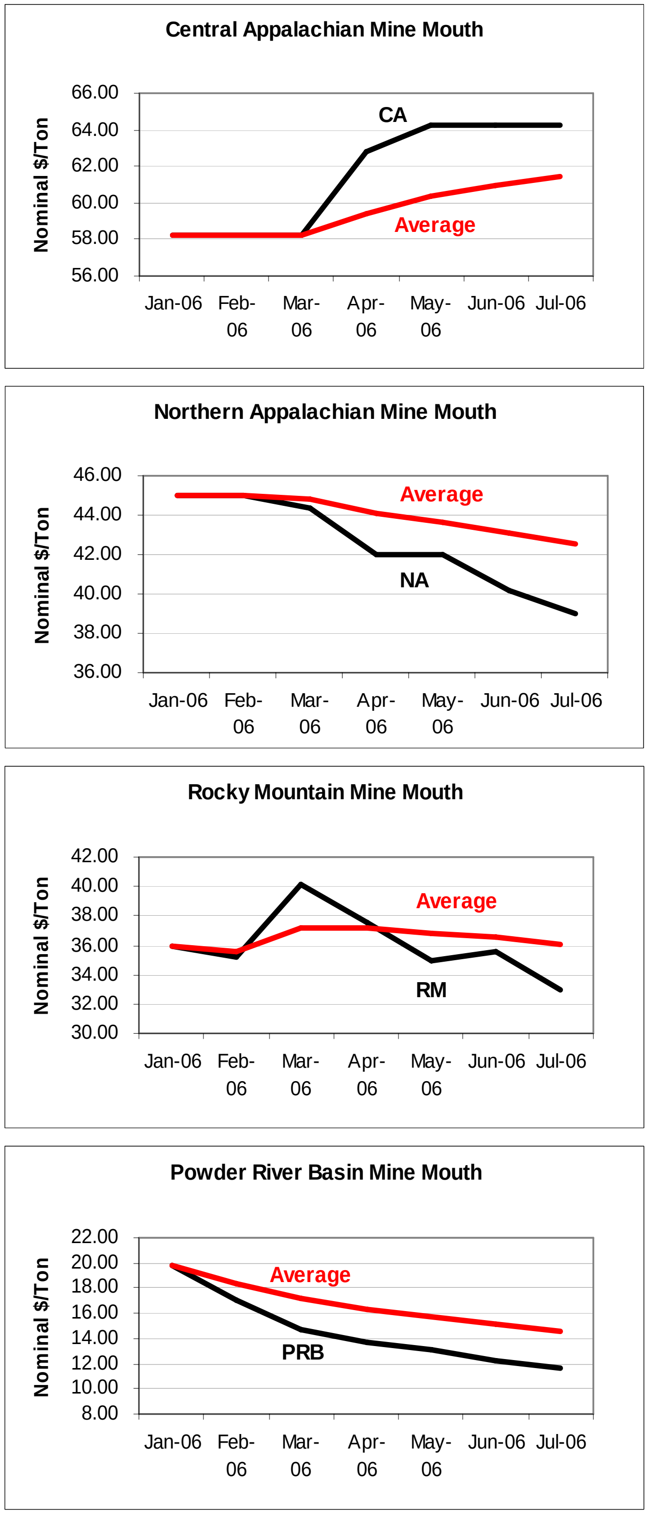
Demand Region[1]	Supply Region[2]	Average Transportation Cost (2006$)
EN	Powder River Basin	13.88
EN	Northern Appalachia	9.20
EN	Central Appalachia	10.75
EN	Rocky Mountain	21.99

[1] Michigan is located in the EN region.
[2] See Figure 13 for a map of the supply regions.

The starting free on board (FOB) mine price for coal was calculated for four supply regions within the United States: the Powder River Basin (PRB), Northern Appalachia, Central Appalachia, and Rocky Mountain. For each of the supply regions, the initial coal cost was calculated based on a seven month average of historical mine mouth prices (January to July, 2006); see Figure 14. This rate was then escalated each year, using the rates indicated in Table 9 (p. 30) to develop the forecast shown in Figure 15. The annual year-to-year percent change from the EIA 2006 Annual Energy Outlook mine mouth forecast for PRB, Rocky Mountain, Central Appalachia, and Northern Appalachia supply regions were utilized to preserve the base trends of the EIA forecast.

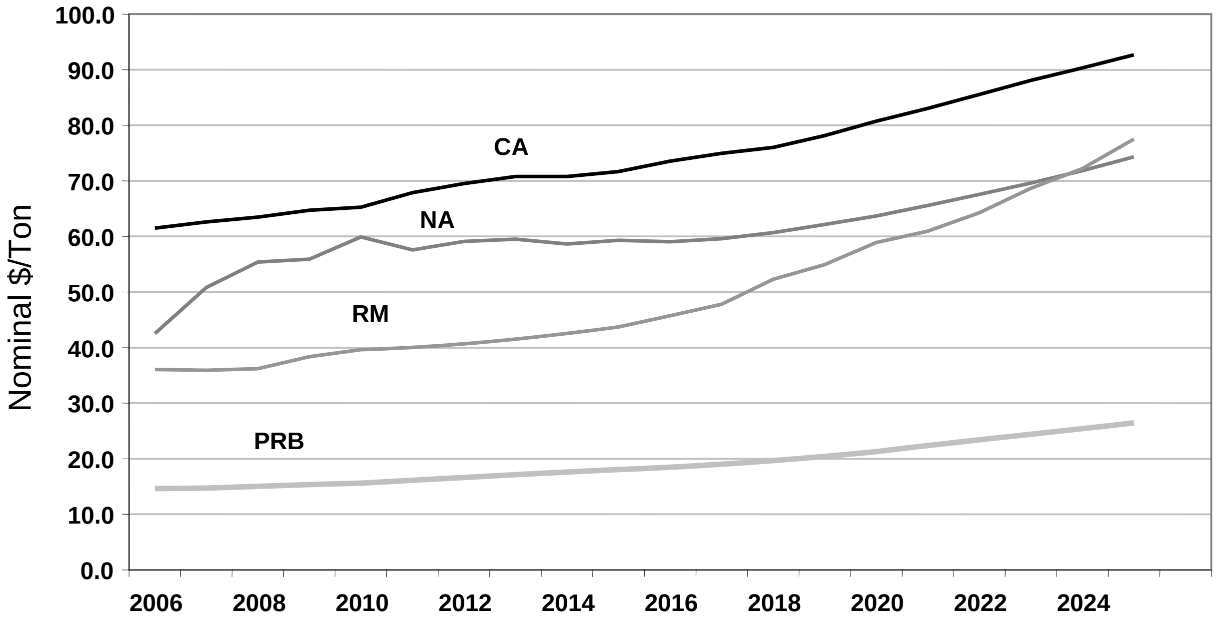
A blend of coal for each Michigan plant was developed from FERC Form 423 data and participant input. The final delivered price of coal was the sum of the mine mouth forecast (see Figure 15) and the average transportation charges, weighted to reflect the coal blend of coal used at each Michigan power plant.

Figure 14: Historical Mine Mouth Prices



Source: EIA Coal News and Markets – Average reflects a month running average.

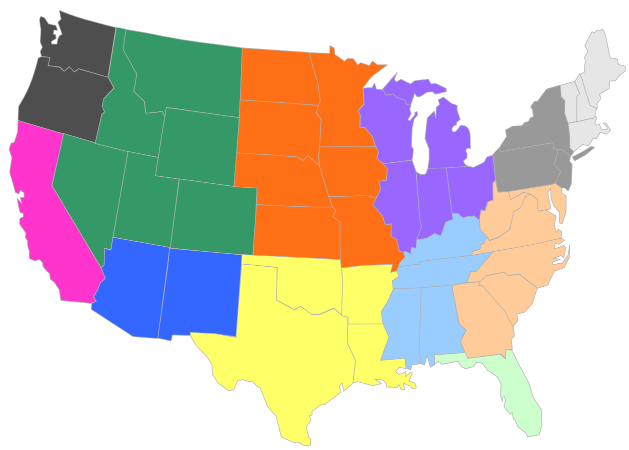
Figure 15: Mine Mouth Forecast



Natural Gas Price Forecast

The starting point for the Natural Gas Price Forecast was the Lower 48 Average Wellhead price forecast from the EIA 2006 Annual Energy Outlook. The process for forecasting natural gas prices concluded with a delivered price for 12 EIA-defined distribution regions, shown in the Figure 16.

Figure 16: EIA Natural Gas Distribution Regions



Source: EIA, 2006, Table 102: Lower 48 Natural Gas Production and Wellhead Prices by Supply Region.

The EIA Wellhead forecast was adjusted upward by 13.3 percent to account for the median historical difference between wellhead prices and Henry Hub Prices. This upward adjustment resulted from an analysis that compared historical wellhead prices and historical Henry Hub prices for their correlation, standard deviation, average percentage difference, and median percentage difference. The median percentage difference was used to scale the Wellhead price to Henry Hub, which is the same methodology employed by EIA.[4] The difference between the EIA delivered price forecast[5] and the Henry Hub forecast (see Figure 17) was used to create a matrix of basis points between Henry Hub and the various distribution regions depicted in Figure 16.

The year–to–year percent change from the wellhead price forecast from the EIA 2006 Annual Energy Outlook was used to preserve the base trends of the EIA forecast. The starting price for the forecast was the rolling one-month average of 18-month NYMEX futures strips (September 2006 through February 2008).

Figure 17: Henry Hub Natural Gas Price Forecast

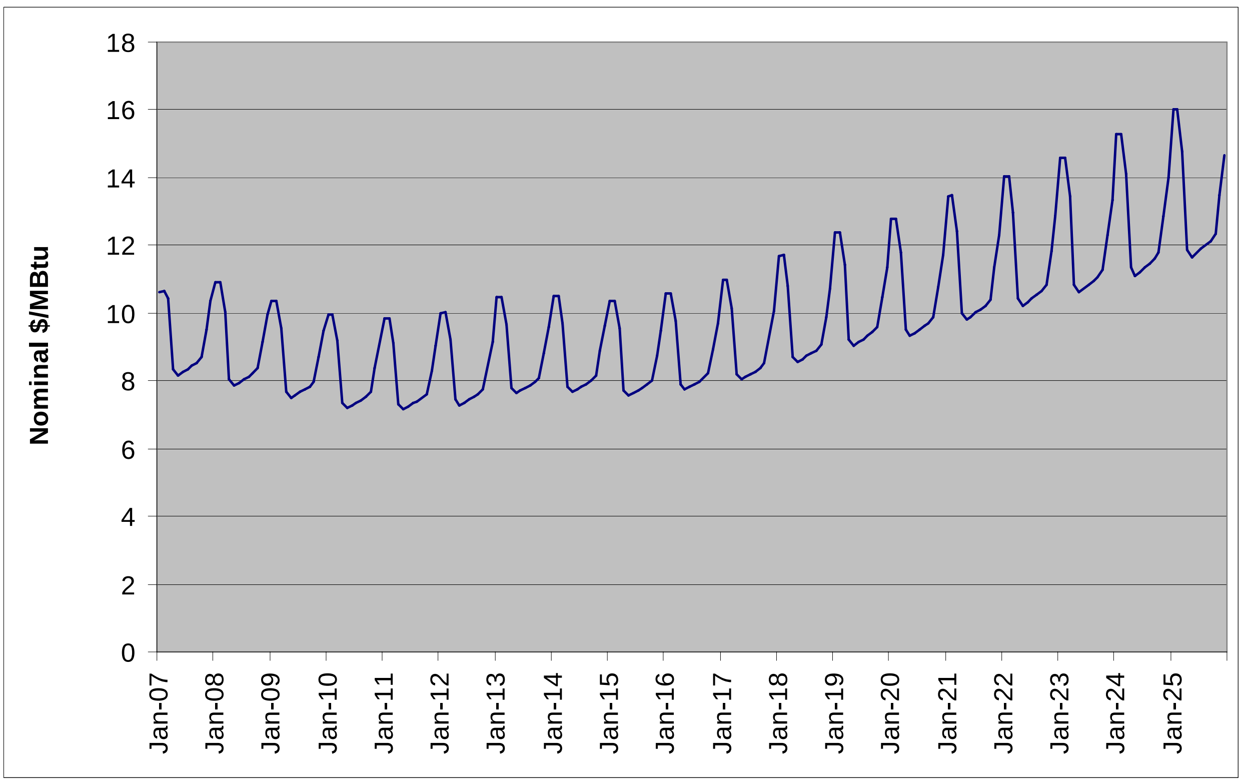


Figure note: Peaks reflect winter, and valleys reflect summer prices.

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4 http://www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html.

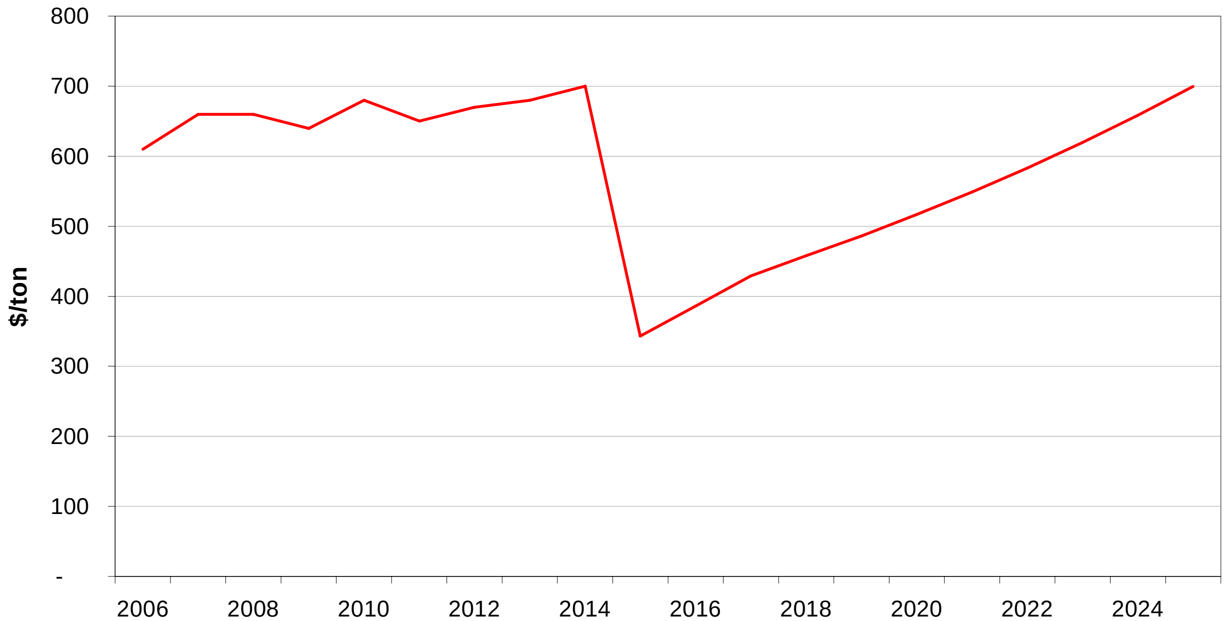
5 2006 EIA Annual Energy Outlook, Table 106: Natural Gas Delivered Prices by End-Use Sector and Census Division.

Emissions Price Forecast

The SO_2 price forecast shown in Figure 18, is based on Evomarkets' SO_2 allowance forwards, May 2006, and makes appropriate adjustments for Clean Air Interstate Transport Rule (CAIR)[6] provisions requiring a 2:1 retirement ratio of allowances in the years 2010-2014, and 2.86:1 retirement ratio of allowances in years 2015 and beyond.

The NOx price forecast, shown in Figure 19, takes into account CAIR provisions requiring both an annual and a seasonal NOx trading program beginning in 2009.[7]

Figure 18: SO_2 Emission Price Forecast



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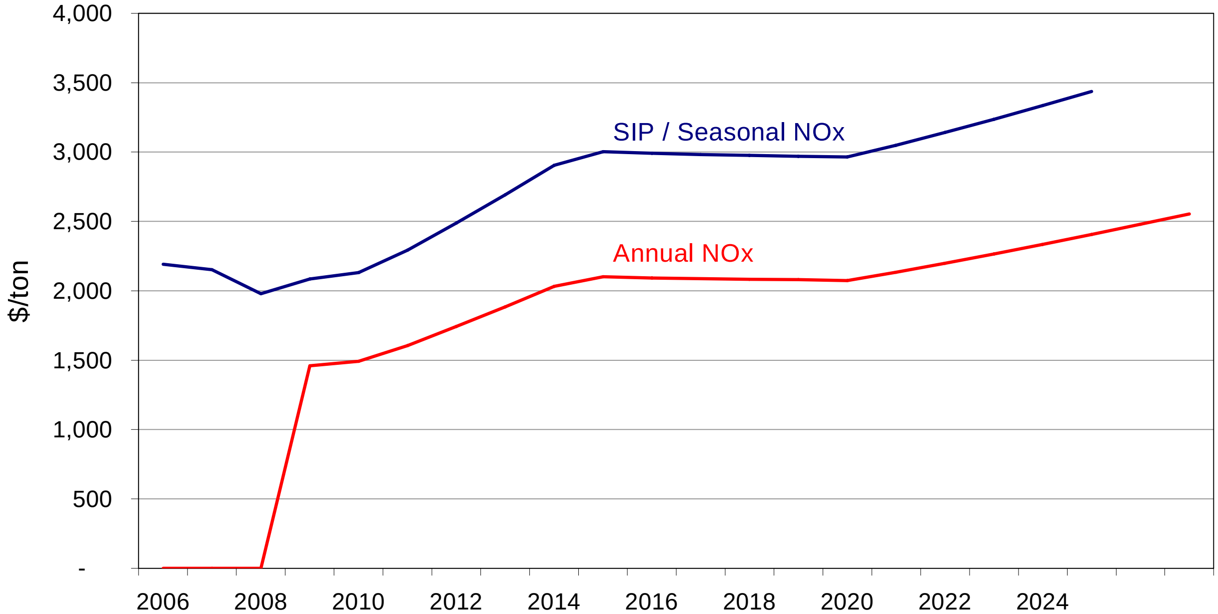
[6] For more information on CAIR, see http://www.epa.gov/cair/.

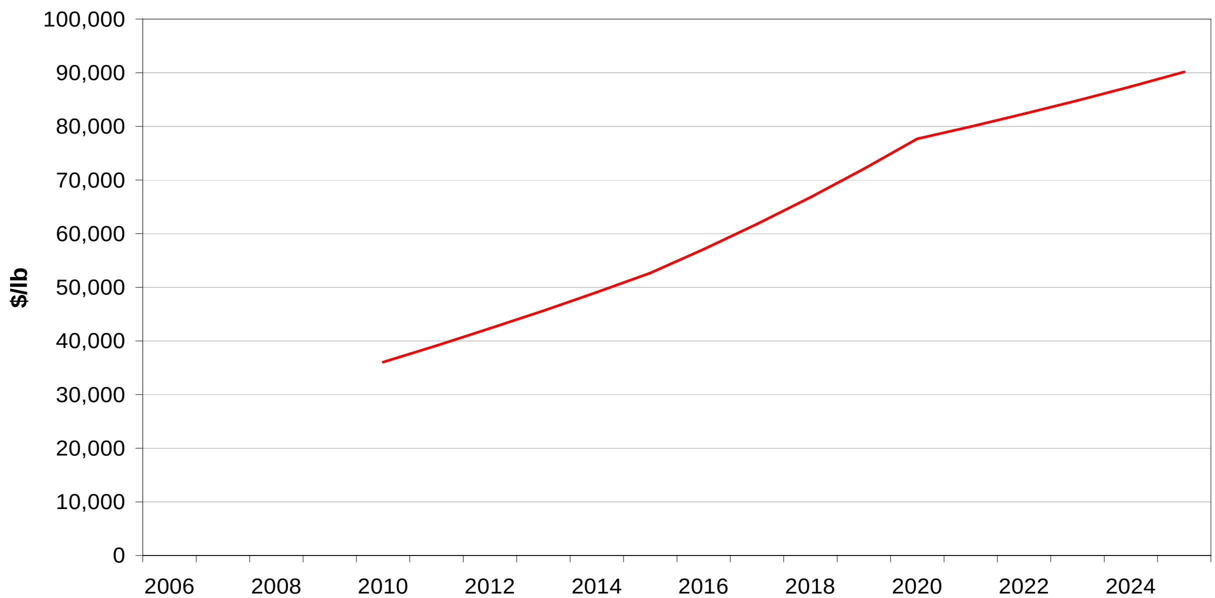
[7] The long-term NOx forecast is derived from the EPA projections (EPA-452/R-05-003, March 2005).

Figure 19: NO_X Emission Price Forecast



The mercury (Hg) forecast shown in Figure 20, began with an emission price of $40,000/lb in 2010 and was then escalated at the same rate as the GDP deflator. In 2018, the price was adjusted up by 40 percent to reflect the effects of Phase II of the EPA's Clean Air Mercury Rule (CAMR) initiative and was then escalated at the GDP deflator rate shown in Table 9 (p. 30).

Figure 20: Mercury Emission Price Forecast – 2010-2025

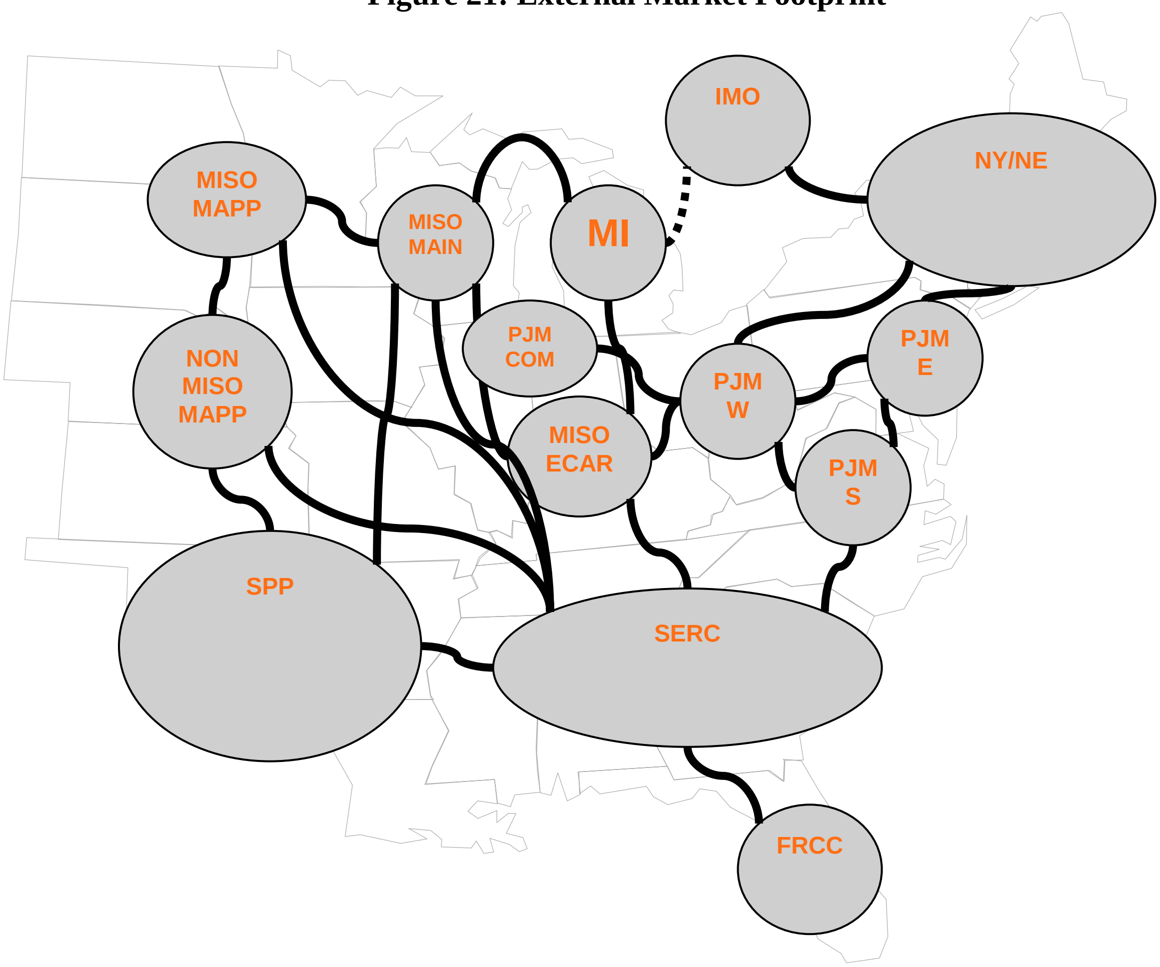


4.3.4 External Market Forecast

The external non-firm energy market forecast was developed using NewEnergy's MarketPower® system. MarketPower® is a regional capacity and energy market forecasting system and was used to produce the capacity and energy price forecasts. This software simulates regional power markets at a macro-economic level. MarketPower® performs the unit dispatch in the various regional markets based on bid prices derived from a percentage of operating costs plus fixed adders. Prices are determined by matching generator bids to demand for each area, subject to transmission transfer limits, tariffs, and generation energy limits (hydro inflow energy, non-utility generator contract limits, and pumped storage). MarketPower® additionally assesses when and where new capacity would be added based on market drivers. In this model, existing generators can also be mothballed, restarted or converted to a different technology, depending on variations in market conditions. Separate prices can be produced for capacity and energy, or a single "all-in" commodity price can be produced.

The assumptions for the broader market were consistent with the assumptions made for the Michigan study. The Figure 21 represents the broader regional market:

Figure 21: External Market Footprint



Figures 22 and 23 present the external market price information. The spot-market on and off-peak values represent the energy price forecasts for external spot-markets that Michigan can purchase from or sell to, on a non-firm basis.

Figure 22: Michigan Lower Peninsula External Market Price Forecast

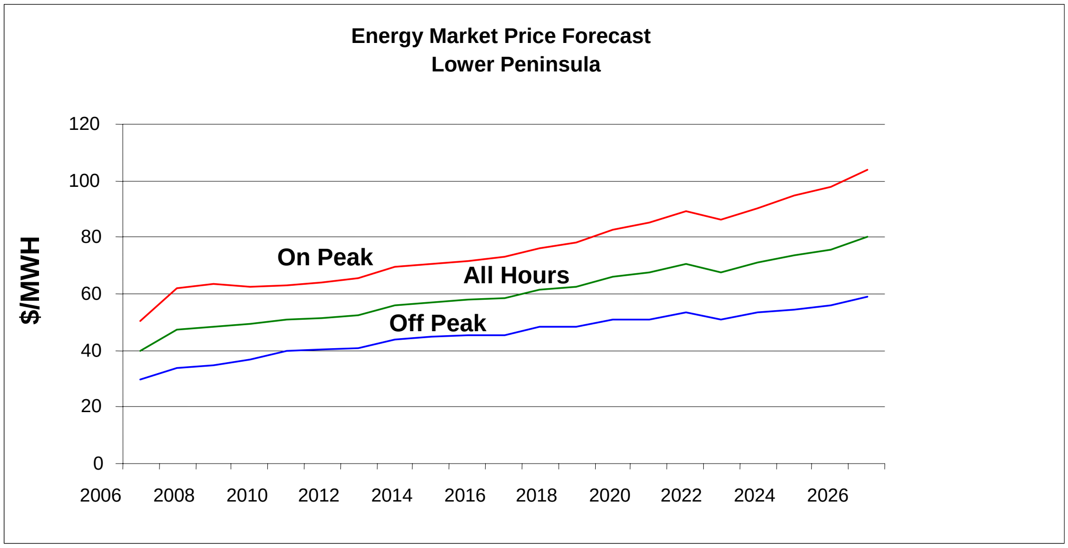
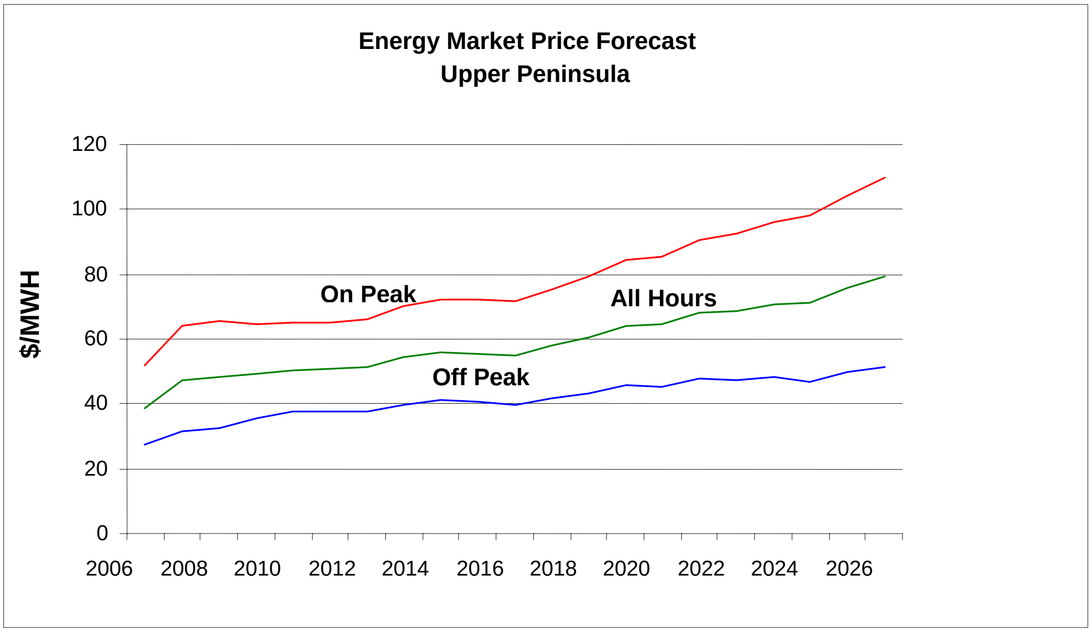


Figure 23: Michigan Upper Peninsula Market Price Forecast



4.3.5 Economic Forecast

The Table 9 presents the remaining economic assumptions from CNF Update Workgroup.

Table 9: Economic Assumptions

<table>
<tr><th colspan="3">Factor</th><th>Escalation Rate</th><th>Notes, Data Sources</th></tr>
<tr><td colspan="3">Construction Costs</td><td>2.47%</td><td rowspan="3">Construction and O&M costs are assumed to escalate at the same rate as gross domestic product.</td></tr>
<tr><td colspan="3">Variable O&M</td><td>2.47%</td></tr>
<tr><td colspan="3">Fixed O&M</td><td>2.47%</td></tr>
<tr><td colspan="3">Gross Domestic Product</td><td>2.47%</td><td>Source: www.eia.doe.gov/oiaf.aeo/pdf/aeotab_19.pdf</td></tr>
<tr><td colspan="3">Interest Paid on Debt</td><td>9.28%</td><td>Calculated to yield an after tax cost of capital of 8.04%</td></tr>
<tr><td rowspan="6">Fuel Types</td><td rowspan="4">Coal Supplies Regions</td><td>Powder River Basin</td><td>2.53%</td><td rowspan="6">Fuel escalation rates represent delivered costs.</td></tr>
<tr><td>Northern Appalachia</td><td>2.81%</td></tr>
<tr><td>Central Appalachia</td><td>2.15%</td></tr>
<tr><td>Rocky Mountain</td><td>3.33%</td></tr>
<tr><td colspan="2">Natural Gas</td><td>2.94%</td></tr>
<tr><td colspan="2">Uranium</td><td>2.80%</td></tr>
</table>

5. Resource Plans

5.1 Overview

The objective function for the Michigan resource plan optimization was to minimize the present value of utility incremental generating costs over the planning period. Resource plans were subject to a long-run minimum target reserve margin of 15 percent for the Michigan system. Individually, METC and ITC experienced minimum reserve margins of 10 percent, phased in over the planning horizon. No additional generating units were allowed to be added once the minimum reserve requirement had been met for any given year. In addition, the modeling assumed that no more than one 500 MW baseload unit would be commissioned per area (that is, METC and ITC) per year.

Table 10 presents the projected future reserve margins if no additional resources were added to Michigan's resource portfolio.

Table 10: Reserve Margin Analysis

	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	1,137	1,496	1,930	2,263	2,893

The Tables 11 and 12 provide an overview of the modeling results for each of the scenarios and sensitivities considered in the Michigan IRP process.

Table 11: Summaries of Scenarios and Sensitivities
(Present Value Revenue Requirements, Capacity Additions, and Ending Reserve Margins)

Scenario		10-Year PVRR ($ millions)	20-Year PVRR ($ millions)	10-Year Total Capacity Additions (MW)	20-Year Total Capacity Additions (MW)	10-Year Ending Reserve Margin (%)	20-Year Ending Reserve Margin (%)
Central Station		**$32,073.0**	**$56,716.9**	**3,440**	**11,260**	**15.26%**	**15.52%**
Sensitivity Analyses	High Load	$35,512.2	$64,116.8	6,740	15,040	15.26%	15.63%
	Low Load	$28,873.2	$49,811.6	660	7,640	17.28%	15.95%
	Reduced Import	$32,169.2	$57,004.8	3,440	11,220	15.26%	15.40%
	Expanded Transmission	$32,329.1	$57,085.5	2,660	10,300	12.53%	12.56%
Emissions		**$36,956.6**	**$70,752.2**	**3,440**	**10,760**	**15.26%**	**16.04%**
Sensitivity Analyses	High Load	$40,832.7	$79,492.7	6,760	14,240	15.33%	15.26%
	Low Load	$33,321.8	$62,254.7	320	7,480	15.96%	17.69%
	Renewable & Energy Efficiency	$36,098.0	$65,594.5	3,026	10,079	16.25%	16.89%
	EE Only	$36,189.0	$66,707.5	3,249	10,261	16.09%	16.53%
Renewable Energy		**$32,506.9**	**$57,496.7**	**3370**	**11,218**	**15.97%**	**16.28%**
Sensitivity Analyses	High Load	$35,929.4	$64,758.6	6,699	14,698	15.98%	15.48%
	Low Load	$29,436.3	$50,797,8	599	7,238	18.07%	15.55%
Energy Efficiency		**$31,510.1**	**$53,794.5**	**3,249**	**10,581**	**16.09%**	**15.73%**
Sensitivity Analyses	High Load	$34,918.3	$61,040.0	6,569	14,241	16.08%	15.45%
	Low Load	$28,638.7	$47,384.1	1,609	6,781	23.11%	15.53%
	Reduced Energy Efficiency Penetration	$32,208.7	$55,765.2	3,267	10,700	15.69%	15.36%
Energy Efficiency with Renewable Energy		**$31,998.1**	**$54,623.2**	**3,028**	**10,359**	**16.25%**	**15.95%**
Sensitivity Analyses	High Load	$35,354.4	$61,780.4	6,188	13,899	15.69%	15.28%
	Low Load	$29,246.5	$48,407.9	2,208	6,579	26.70%	15.86%
	Reduced Energy Efficiency Penetration	$32,692.1	$56,546.1	3,386	10,518	17.10%	15.70%
Combustion Turbine Only		**$32,126.9**	**$58,987.6**	**3,520**	**11,200**	**15.54%**	**15.34%**
Sensitivity Analyses	High Load	$35,630.2	$68,096.6	6,720	14,880	15.20%	15.18%
	Low Load	$28,856.0	$50,737.5	320	7,680	15.96%	16.09%

[1]Combined heat and power (CHP) resources were modeled along with renewable energy, in all renewable energy scenarios and sensitivities.

Table 12: Summaries of Scenarios and Sensitivities (Modeled Capacity Added by Type of Resource, in Megawatts)

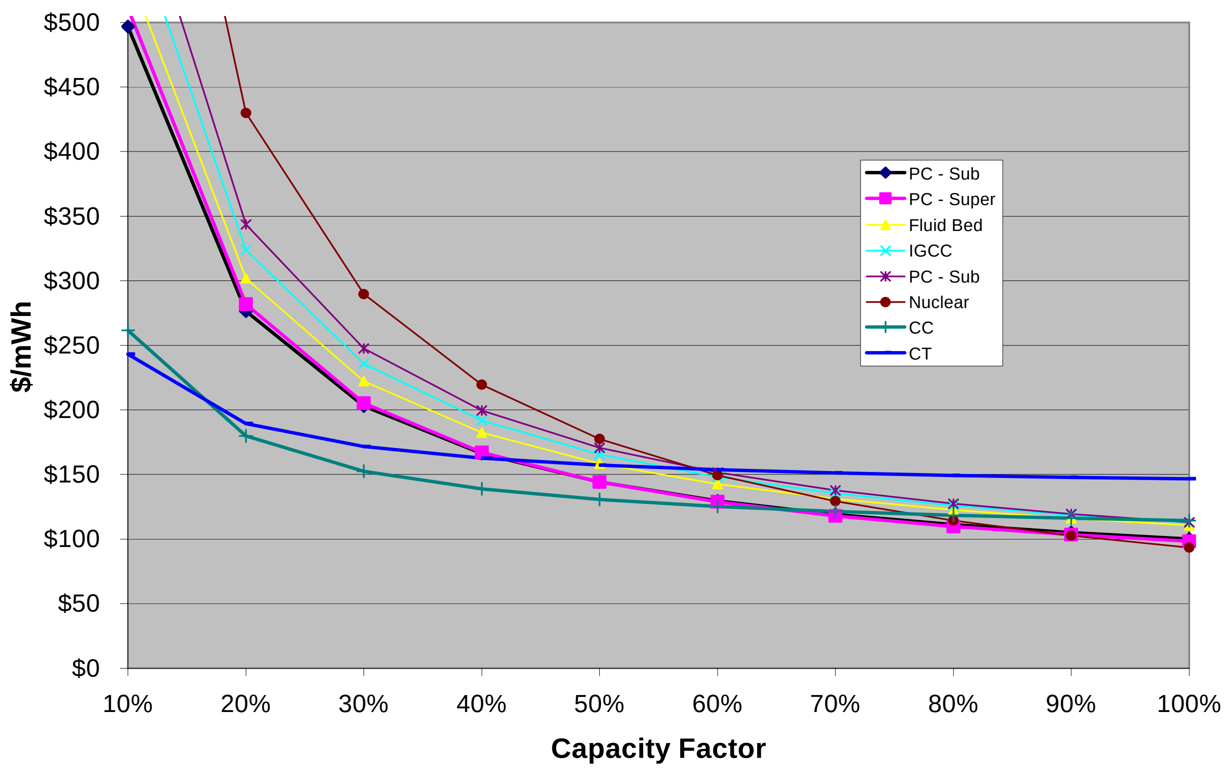
	Scenario	Combustion Turbine (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Nuclear (MW)	Renewable Capacity (MW)[1]	Energy Efficiency (MW)
Central Station		1,760	500	9,000	0	0	0
Sensitivity Analyses	High Load	3,040	2,000	10,000	0	0	0
Sensitivity Analyses	Low Load	640	500	6,500	0	0	0
Sensitivity Analyses	Reduced Import	2,720	1,000	7,500	0	0	0
Sensitivity Analyses	Expanded Transmission	800	1,000	8,500	0	0	0
Emissions		1,760	1,000	2,000	6,000	0	0
Sensitivity Analyses	High Load	2,240	2,000	4,000	6,000	0	0
Sensitivity Analyses	Low Load	480	0	1,000	6,000	0	0
Sensitivity Analyses	Renewable & Energy Efficiency	480	500	500	5,000	798[2]	2,801
Sensitivity Analyses	EE Only	960	0	1,500	5,000	0	2,801
Renewable Energy		1,920	500	8,000	0	798	0
Sensitivity Analyses	High Load	2,400	2,000	9,500	0	798	0
Sensitivity Analyses	Low Load	1,440	0	5,000	0	798	0
Energy Efficiency		1,280	0	6,500	0	0	2,801
Sensitivity Analyses	High Load	1,440	2,000	8,000	0	0	2,801
Sensitivity Analyses	Low Load	480	0	3,500	0	0	2,801
Sensitivity Analyses	Reduced Energy Efficiency Penetration	1,280	0	7,500	0	0	1,920
Energy Efficiency with Renewable Energy		1,760	0	5,000	0	798	2,801
Sensitivity Analyses	High Load	800	2,000	7,500	0	0	2,801
Sensitivity Analyses	Low Load	480	0	2,500	0	0	2,801
Sensitivity Analyses	Reduced Energy Efficiency Penetration	800	500	6,500	0	0	1,920
Combustion Turbine Only Case		11,200	0	0	0	0	0
Sensitivity Analyses	High Load	14,880	0	0	0	0	0
Sensitivity Analyses	Low Load	7,680	0	0	0	0	0

[1] Combined heat and power (CHP) resources were modeled along with renewable energy, in all renewable energy scenarios and sensitivities.
[2] Renewable Capacity represents on-peak capacity in 2025, using a capacity factor of 12.5% for wind and 100% for all other renewable resources modeled.

5.2 Results

For each scenario, 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[8], fixed and variable operating costs including fuel costs, construction and operating cost escalations, allowance for funds used during construction (AFUDC), capital depreciation, property and income taxes, and insurance costs. The screening curve for the base case cost assumptions is depicted in Figure 24.

Figure 24: Base Case Technology Screening Curves



It is evident from the curves, for example, that the levelized cost of nuclear units exceeds the costs of other technologies over the entire range of plant capacity factors. On this basis, nuclear units were "screened-out" of the base model run.

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[8] Overnight construction costs do not include financing costs.

On the basis of this screening curve, the following resources were screened out of the Central Station Base Case Scenario analyses:

- Fluidized Bed Coal
- IGCC
- IGCC – PRB Coal
- Nuclear

The remaining alternatives, combustion turbine, combined cycle, and pulverized super-critical coal, were included in the resource optimization. Note that the pulverized super-critical coal is nearly the same cost as sub-critical. Therefore, for the base case, the super-critical coal plant can be thought of as a placeholder for either type of coal baseload capacity. The results of the Central Station Base Case are summarized in Figure 25 and Figure 26.

Figure 25: Central Station Base Case Summary Results

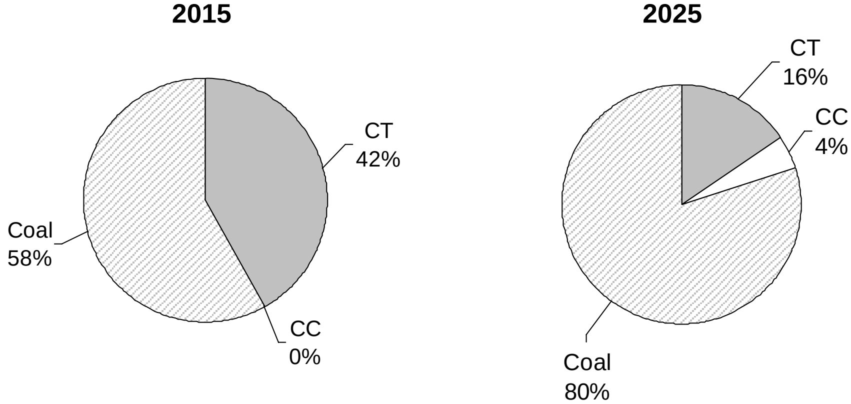
- 2006 to 2015
- Capacity Additions (in MW)
  - CT 1,440
  - CC
  - PC 2,000
  - Nuclear
  - Renewable
  - Conservation
- Total 3,440

- Demand Growth 1.17 %
- Reserve Margin 15.26 %
- Plan Costs
  - NPV Utility Cost $ 32,073.0 M
  - NPV Emissions $ 3,385.6 M
  - NPV CO2 $ 0.00 M

- 2006 to 2025
- Capacity Additions (in MW)
  - CT 1,760
  - CC 500
  - PC 9,000
  - Nuclear
  - Renewable
  - Conservation
- Total 11,260

- Demand Growth 1.21 %
- Reserve Margin 15.52 %
- Plan Costs
  - NPV Utility Cost $ 56,716.9 M
  - NPV Emissions $ 5,602.8 M
  - NPV CO2 $ 0.00 M

Figure 26: Central Station Base Case Expansion Plan Capacity Mix



The Base Central Station Expansion plan exhibited a number of key resource planning results. The State of Michigan is in need of approximately 300 MW of capacity by 2008 to meet planning reserve criteria. This is exhibited by the fact that the model shows three combustion turbines being added in 2008, or as soon as practical. After achieving the capacity necessary for reliability in the early years, the State of Michigan was in need of baseload energy. As soon as available, the Central Station expansion plan selected baseload energy resources. After 2012 when pulverized super-critical coal was available, it became the preferred resource. Throughout the remaining study horizon, coal was the preferred generating technology for the State of Michigan. Table 13 summarizes the expansion plan for the Central Station scenario.

5.3 Sensitivities Analysis

The following sensitivities were performed on the Base Case: High Load, Low Load, Expanded Transmission, and Low Imports. The High Load sensitivity represented a 1.61 percent annual average demand growth rate, whereas the Base Case demand growth rate was 1.21 percent. The Low Load sensitivity represented a 0.76 percent annual demand growth rate. The Expanded Transmission and Low Import sensitivities were defined in Section 4.2.6. The results of the Central Station sensitivities are contained in the expansion results file located on the Plan website.[9]

The need for near-term capacity for reliability, in the form of combustion turbines (CTs) in 2008, was common across all sensitivities except the Low Load sensitivity. Also, in the Energy Efficiency Scenarios, the number of CTs added from 2008 through 2012 is reduced from nine to three units. This is due to an additional 570 MW of load management in the energy efficiency program that displaces some of the CTs. CTs were added as soon as the modeled construction schedule could make them available. In the Low Load sensitivity, the reduced load requirements offset the need for reliability capacity. Across all of the sensitivities, the need for energy production capacity was prevalent. Under all scenarios, super-critical coal (PC) units were the predominant choice for new generation. This modeling conclusion underscores the need for long-term baseload capacity in the State of Michigan.

[9] See http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/expansion_results.pdf.

Table 13: Central Station Base Case Expansion Plan (Units Added and Plant Types)

Total Units Added	Plant Type & Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
2	CT-METC			1	1						
7	CT-ITC			2		2	2				
2	CT-ATC2							1			
0	CC-METC										
1	CC-ITC										
0	CC-ATC2										
6	COAL-METC										
12	COAL-ITC							1	1	1	1
0	COAL-ATC2										
0	CFB-ATC										

Plant Type & Region	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CT-METC										
CT-ITC										1
CT-ATC2	1									
CC-METC										1
CC-ITC										
CC-ATC2										
COAL-METC	1	1		1		1	1	1		
COAL-ITC	1		1	1	1	1	1	1	1	
COAL-ATC2										
CFB-ATC										

Resource construction lead time proved to be a major driver of the near-term expansion plan choices. As soon as capacity becomes available, given the construction lead-times incorporated in the planning assumptions, the model adds CTs in order to serve the capacity reliability needs of the Michigan system. This can be seen in nearly every scenario and sensitivity, through the addition of CT capacity in the 2008 to 2011 timeframe. Coal units are added as soon as the modeled construction schedule assumes they can be completed. Pulverized coal super-critical units dominate the expansion plan from 2012 through the end of the study horizon.

The assumption regarding Low Imports did not make a substantial impact on the expansion plans in the near-term. Through 2015, the expansion plans across all scenarios assuming Low Imports were identical. This was due to the modeling assumption, as stated previously, that no external capacity is bought or sold in this sensitivity analysis.

The Expanded Transmission case adds, and incurs costs associated with, 2,500 MW of transmission upgrades. The added transmission capacity directly displaces only approximately 900 MW of new generation, however. This reduction in generation need is a result of reducing the reserve margin from 15 to 12 percent. In addition, the weighted cost of capital of the new transmission is 9.91 percent and recovered over a 40-year life, which is considerably higher than that of new generation, which is modeled on an 8.04 percent cost of capital. Given these assumptions, the Expanded Transmission case with the transmission upgrade costs more, on a present value basis, than the Central Station Base case.

5.4 Scenarios

5.4.1 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:

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

For the Emissions Scenario, resource options were evaluated on a levelized cost basis to screen out alternatives that would have limited economic viability. On the basis of this screening curve, as shown in Figure 27, fluidized-bed coal and IGCC technologies were not included in the analysis. The remaining alternatives: combustion turbine, combined cycle, pulverized sub-critical coal, and nuclear were included in the resource optimization.

Under the Emissions Scenario, the need for near-term capacity to meet reliability requirements was still apparent. The longer term need for energy production was met through the addition of nuclear resources. Combined cycle and coal units were built in the near-term to meet the energy requirements of Michigan until new nuclear generation became available in 2018.

A major difference emerging from the Emissions Scenario was the added costs associated with emission allowances. Table 14 outlines the differences in the cost components.

The Emissions Scenario was further subjected to High Load, Low Load, Energy Efficiency, and Energy Efficiency with Renewable Energy sensitivities. The results of the Emissions Scenario sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

Figure 27: Emissions Scenario Screening Curve

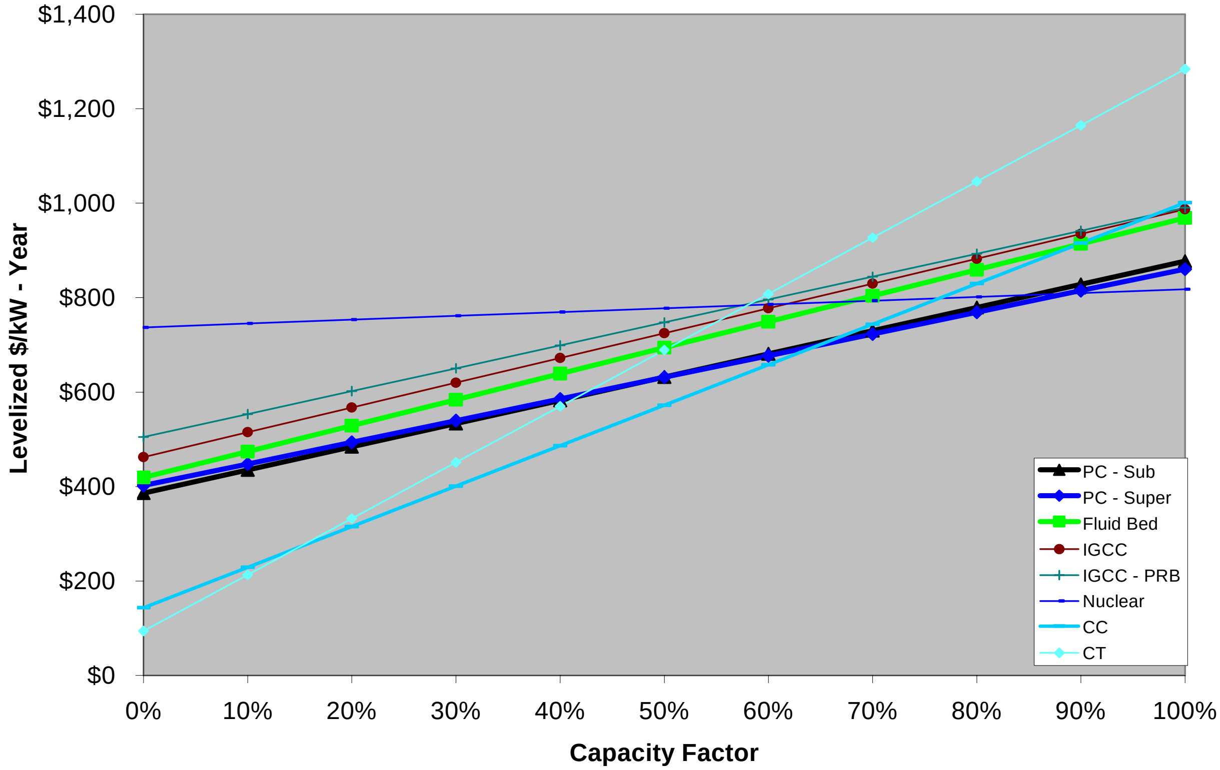


Table 14: Comparison of Cost Components in Emissions and Central Station Scenarios 2006-2025

4. Scenario	5. 20-Year PVRR ($ millions)	6. PV Total Emissions ($ millions)[1]	7. PV Total Carbon ($ millions)
Central Station	56,716.9	5,602.8	0
Emissions	70,752.2	18,991.7	13,358.9
[1]Includes cost of carbon emissions			

5.4.2 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:

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

Table 15: Comparison of Energy Efficiency and Central Station Scenarios – 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Energy Efficiency (MW)	PVRR ($ millions)
Central Station	1,760	500	9,000	0	56,716.9
Energy Efficiency	1,280	0	6,500	2801	53,794.5

Under the Energy Efficiency Scenario, the need for new capacity in MECS was delayed until 2011, compared to 2008 in the Central Station (Base Case) Scenario. The longer term need for energy production still was met predominantly through the addition of coal resources.

The Energy Efficiency Scenario was further subjected to High Load, Low Load, and Low Energy Efficiency Penetration sensitivities. The results of the Energy Efficiency sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

5.4.3 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:

- 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.
- Wind energy was assumed to have a capacity value, on peak, of 12.5 percent of nameplate capacity.
- Central Station options remained the same but they were re-optimized after taking into account the schedule of renewable energy options.

Under the Renewable Energy Scenario, the need for immediate reliability capacity was still apparent. The longer term need for baseload energy production was met primarily through the addition of coal generating technology.

Table 16: Comparison of Renewable Energy and Central Station Scenarios 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Integrated Gasification Combined Cycle (MW)	Renewable Resources and CHP (MW)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
Renewable Energy	1,920	500	8,000	0	798	57,496.7

The Renewable Energy Scenario was further analyzed under High Load and Low Load sensitivities. The results of the Renewable Energy Scenario sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

5.4.4 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:

- Energy efficiency programs were scheduled in, and the program cost was incorporated into the present value cost calculation.
- Approximately 570 MW of direct load control was included.
- 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.
- The Central Station options remained the same, but were re-optimized after taking into account the schedule of energy efficiency and renewable energy options.

The Energy Efficiency with Renewable Energy Scenario was further analyzed under High Load, Low Load, and Reduced Energy Efficiency Penetration sensitivities. The Reduced Penetration sensitivity reduced the amount of demand reduction associated with energy efficiency from 2,801 MW to 1,920 MW and increased the associated costs. The Reduced Energy Efficiency Penetration sensitivity closely approximates the estimates for energy efficiency program performance that were modeled in the 2005 Michigan Capacity Needs Forum. The results of the Energy Efficiency with Renewable Energy sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

Table 17: Comparison of Central Station and Energy Efficiency with Renewable Energy Scenarios 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Energy Efficiency (MW)	Renewable Resources and CHP (MW)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
EE with Renewable	1,760	0	5,000	2,801	798	54,623.2

[1] Included in modeling for the Renewable Energy Scenario was 178 MW of CHP capacity that is not necessarily assumed to be powered by renewable fuels.

5.5 Combustion Turbines Only Scenario

The final scenario modeled was that of an expansion plan limited to combustion turbines alone. In this CT Only Scenario, the super-critical coal and the combined cycle options were not considered as options available in this scenario.

Table 18: Comparison of Base Case and Combustion Turbines Only Scenarios 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Energy Efficiency (MW)	Renewable Resources and CHP (MW)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
Combustion Turbines Only	11,200	0	0	0	0	58,987.6

The CT Only Scenario was further analyzed under High Load and Low Load sensitivities. The results of the CT Only sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

The following tables examine all six scenarios under base case demand assumptions.

Table 19: 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)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
Emissions	1,760	1,000	2,000	6,000	0	70,752.2
Energy Efficiency	1,280	0	6,500	0	2,801	53,794.5
Renewable	1,920	500	8,000	0	798	57,496.7
EE with Renewable	1,760	0	5,000	0	3,599	54,623.2
CT Only	11,200	0	0	0	0	58,987.6

6. Generation Capability Tables

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Combined Cycle (existing)	Dearborn Industrial Generation LLC:CC1	760.00
Combustion Turbine Gas	Ann Arbor GT:1	3.20
Combustion Turbine Gas	Belle River:GT1	75.00
Combustion Turbine Gas	Belle River:GT2	75.00
Combustion Turbine Gas	Belle River:GT3	75.00
Combustion Turbine Gas	Delray:11-1	63.00
Combustion Turbine Gas	Delray:12-1	64.00
Combustion Turbine Gas	DTE East China:GT10	76.00
Combustion Turbine Gas	DTE East China:GT7	76.00
Combustion Turbine Gas	DTE East China:GT8	76.00
Combustion Turbine Gas	DTE East China:GT9	76.00
Combustion Turbine Gas	Greenwood:GT1	75.00
Combustion Turbine Gas	Greenwood:GT2	75.00
Combustion Turbine Gas	Greenwood:GT3	75.00
Combustion Turbine Gas	Hancock (DETED):1	11.00
Combustion Turbine Gas	Hancock (DETED):2	18.00
Combustion Turbine Gas	Hancock (DETED):3	17.00
Combustion Turbine Gas	Hancock (DETED):4	17.00
Combustion Turbine Gas	Hancock (DETED):5	38.00
Combustion Turbine Gas	Hancock (DETED):6	40.00

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Gas	Hutzel Hospital:GTGS2	1.60
Combustion Turbine Gas	Main Street (SEAW):GTGS6	6.13
Combustion Turbine Gas	MPPA : Belle River	234.00
Combustion Turbine Gas	Northeast (DETED):1	14.75
Combustion Turbine Gas	Northeast (DETED):2	14.75
Combustion Turbine Gas	Northeast (DETED):3	14.75
Combustion Turbine Gas	Northeast (DETED):4	14.75
Combustion Turbine Gas	Pine Street (SEAW):GTGS4	5.00
Combustion Turbine Gas	Sumpter Township:GT1	72.25
Combustion Turbine Gas	Sumpter Township:GT2	72.25
Combustion Turbine Gas	Sumpter Township:GT3	72.25
Combustion Turbine Gas	Sumpter Township:GT4	72.25
Combustion Turbine Gas	Ubly:GTGS2	4.04
Combustion Turbine Gas	Wayne County Airport:GTGS3	17.10
Combustion Turbine Oil	Belle River:GTOL5	13.75
Combustion Turbine Oil	Caro:GTOL6	8.55
Combustion Turbine Oil	Colfax (DETED):GTOL5	13.75
Combustion Turbine Oil	Conners Creek:GTOL2	5.50
Combustion Turbine Oil	Croswell Plant:3	1.21
Combustion Turbine Oil	Croswell Plant:GTGS4	4.02
Combustion Turbine Oil	Dayton (DETED):GTOL5	10.00
Combustion Turbine Oil	Fermi:GTOL4	51.00
Combustion Turbine Oil	Harbor Beach:GTOL2	4.00
Combustion Turbine Oil	Michigan Automotive Research:1-8	0.00
Combustion Turbine Oil	Mistersky:GT1	30.00
Combustion Turbine Oil	Monroe (DETED):GTOL5	13.75
Combustion Turbine Oil	Northeast (DETED):5	17.00
Combustion Turbine Oil	Northeast (DETED):6	19.50
Combustion Turbine Oil	Northeast (DETED):7	19.50
Combustion Turbine Oil	Oliver:GTOL5	13.75
Combustion Turbine Oil	Pine Street (SEAW):GTOL2	2.28
Combustion Turbine Oil	Placid 12:GTOL5	13.75
Combustion Turbine Oil	Putnam (DETED):GTOL5	13.75
Combustion Turbine Oil	River Rouge:GTOL4	11.00
Combustion Turbine Oil	Slocum:GTOL5	13.75

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Oil	St. Clair:11	19.00
Combustion Turbine Oil	St. Clair:GTOL2	5.50
Combustion Turbine Oil	Superior:GTOL4	52.00
Combustion Turbine Oil	Ubly:GTOL5	4.51
Combustion Turbine Oil	Wilmont:GTOL5	13.75
Hydro Run-of-River	DETED Small Hydros:HYOP2	1.40
Hydro Run-of-River	Ford Lake:HYOP1	0.85
Hydro Run-of-River	French Landing Dam:HYOP1	1.80
Interruptible Load	DETED Interruptible:1	0.00
Landfill Gas	Ann Arbor Generating Station:1	1.60
Landfill Gas	Arbor Hills Generating Facility: CC	17.40
Landfill Gas	Carleton Farms Generating Project:1	6.40
Landfill Gas	EQ - Waste Energy Services Inc: GTGS4	1.40
Landfill Gas	Lyon Generating Facility:GTGS7	4.50
Landfill Gas	Pine Tree Acres:GTGS5	4.00
Landfill Gas	Riverview Energy Systems:GTGS2	6.60
Landfill Gas	Sumpter Energy Assoc.: GTGS10	12.00
Nuclear (existing)	Fermi:2	1111.00
Steam Turbine Coal	Belle River:ST1	509.00
Steam Turbine Coal	Belle River:ST2	517.00
Steam Turbine Coal	Harbor Beach:1	103.00
Steam Turbine Coal	Monroe (DETED):1	770.00
Steam Turbine Coal	Monroe (DETED):2	785.00
Steam Turbine Coal	Monroe (DETED):3	785.00
Steam Turbine Coal	Monroe (DETED):4	775.00
Steam Turbine Coal	NAO GM Pontiac Power Plant:1	28.94
Steam Turbine Coal	River Rouge:2	238.00
Steam Turbine Coal	River Rouge:3	272.00
Steam Turbine Coal	St. Clair:1	153.00
Steam Turbine Coal	St. Clair:2	162.00
Steam Turbine Coal	St. Clair:3	171.00
Steam Turbine Coal	St. Clair:4	158.00
Steam Turbine Coal	St. Clair 6	321.00
Steam Turbine Coal	St. Clair 7	450.00
Steam Turbine Coal	Trenton Channel:7	0.00
Steam Turbine Coal	Trenton Channel:8	210.00

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Steam Turbine Coal	Trenton Channel:9	520.00
Steam Turbine Coal	Wyandotte (WYAN):7	30.00
Steam Turbine Coal	Wyandotte (WYAN):8	22.00
Steam Turbine Gas	Conners Creek:15	0.00
Steam Turbine Gas	Conners Creek:16	215.00
Steam Turbine Gas	River Rouge:1	234.00
Steam Turbine Gas	Wyandotte (WYAN):5	20.00
Steam Turbine Oil	Greater Detroit Resource Recovery: GEN1	30.75
Steam Turbine Oil	Greenwood:1	785.00
Steam Turbine Oil	Mistersky:5	34.29
Steam Turbine Oil	Mistersky:6	38.96
Steam Turbine Oil	Mistersky:7	46.75
Steam Turbine Other	Refuse 2:1	20.00

Table 21: METC Region, Consumers Energy Company Existing Generation Resources

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Combined Cycle (existing)	Ada Cogeneration Limited Partn:CC	29.40
Combined Cycle (existing)	Covert:CC3	384.00
Combined Cycle (existing)	Covert:CC4	384.00
Combined Cycle (existing)	Covert:CC5	384.00
Combined Cycle (existing)	Covert:CCGS3	48.00
Combined Cycle (existing)	Jackson:CCA	280.00
Combined Cycle (existing)	Jackson:CCB	280.00
Combined Cycle (existing)	Michigan Power L.P.:CC	123.00
Combined Cycle (existing)	Midland Cogeneration Venture (MCV):CC	1240.00
Combined Cycle (existing)	Zeeland (MIR):CC1	532.00
Combustion Turbine Gas	491 E. 48th Street:7	37.60
Combustion Turbine Gas	491 E. 48th Street:8	37.60
Combustion Turbine Gas	491 E. 48th Street:9	83.50
Combustion Turbine Gas	B.E. Morrow GTGS2	34.00
Combustion Turbine Gas	Clinton (CLIN):6	2.00
Combustion Turbine Gas	Coldwater:GTGS2	8.50
Combustion Turbine Gas	Diesel Plant (GHLP):GTGS3	11.90
Combustion Turbine Gas	Diesel Plant – STURGI:6	6.00
Combustion Turbine Gas	Gaylord:GTGS5	85.00

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Gas	Grand Rapids East:1	0.00
Combustion Turbine Gas	Hart:GTGS4	4.82
Combustion Turbine Gas	Hillsdale:GTGS4	17.70
Combustion Turbine Gas	Kalamazoo River Generating Station:GT	68.00
Combustion Turbine Gas	Livingston Generating Station:1	42.90
Combustion Turbine Gas	Livingston Generating Station:2	42.43
Combustion Turbine Gas	Livingston Generating Station:3	42.43
Combustion Turbine Gas	Livingston Generating Station:4	42.43
Combustion Turbine Gas	Renaissance Power Project:GT1	171.00
Combustion Turbine Gas	Renaissance Power Project:GT2	171.00
Combustion Turbine Gas	Renaissance Power Project:GT3	171.00
Combustion Turbine Gas	Renaissance Power Project:GT4	171.00
Combustion Turbine Gas	Straits:1	21.00
Combustion Turbine Gas	Thetford:1	37.00
Combustion Turbine Gas	Thetford:2	37.00
Combustion Turbine Gas	Thetford:3	37.00
Combustion Turbine Gas	Thetford:4	37.00
Combustion Turbine Gas	Thetford:GTGS5	86.00
Combustion Turbine Gas	Weadock:A	17.00
Combustion Turbine Gas	Zeeland (MIR):GT1	149.00
Combustion Turbine Gas	Zeeland (MIR):GT2	149.00
Combustion Turbine Gas	Zeeland (ZBPW):GTGS7	24.00
Combustion Turbine Oil	Alma Modular:GTOL7	0.00
Combustion Turbine Oil	APG Four Mile Substation (PPA):GTOL1	18.25
Combustion Turbine Oil	APG Long Lake Road (PPA):GTOL1	9.00
Combustion Turbine Oil	APG Michigan Limestone (PPA):GTOL1	18.25
Combustion Turbine Oil	APG Rockport (PPA):GTOL1	9.13
Combustion Turbine Oil	Campbell (CEC):A	17.00
Combustion Turbine Oil	Chelsea Modular:GTOL3	0.00
Combustion Turbine Oil	Clinton (CLIN):GTOL5	2.20
Combustion Turbine Oil	Coldwater Modular:GTOL10	0.00
Combustion Turbine Oil	Coldwater:GTOL2	3.50
Combustion Turbine Oil	Diesel Plant (GHLP):5	3.00
Combustion Turbine Oil	Diesel Plant (GHLP):7	5.10
Combustion Turbine Oil	Diesel Plant - STURGI:GTOL4	2.80

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Oil	Frank Jenkins:5	1.70
Combustion Turbine Oil	Frank Jenkins:GTOL2	0.38
Combustion Turbine Oil	Henry Station:GTOL2	15.40
Combustion Turbine Oil	Hillsdale:2	1.90
Combustion Turbine Oil	Marshall (MCWEW):GTGS5	10.70
Combustion Turbine Oil	Saginaw Station:GTOL2	12.60
Combustion Turbine Oil	Sixth Street Mi:1	22.00
Combustion Turbine Oil	St. Louis (STLO):GTGS2	2.50
Combustion Turbine Oil	St. Louis (STLO):GTOL2	1.70
Combustion Turbine Oil	Whiting (CEC):A	17.00
Combustion Turbine Oil	Zilwaukee:1-12	0.00
Combustion Turbine Oil	Zilwaukee:13-33	0.00
Hydro Run-of-River	Ada Dam:HYOP1	1.40
Hydro Run-of-River	Alcona:HYOP2	8.00
Hydro Run-of-River	Allegan Dam:HYOP3	2.50
Hydro Run-of-River	Beaverton (PPA):HYOP1	0.50
Hydro Run-of-River	Black River (PPA):HYOP1	0.84
Hydro Run-of-River	C.W. Tippy:HYOP3	21.00
Hydro Run-of-River	Cascade Dam:HYOP1	1.40
Hydro Run-of-River	CEC Small Hydros:HYOP20	0.00
Hydro Run-of-River	Cheboygan:HYOP1	0.00
Hydro Run-of-River	Commonwealth (Hubbardston PPA):HYOP1	0.22
Hydro Run-of-River	Commonwealth (Irving PPA):HYOP1	0.24
Hydro Run-of-River	Commonwealth (LaBarge PPA):HYOP1	0.70
Hydro Run-of-River	Commonwealth (Middleville PPA):HYOP1	0.20
Hydro Run-of-River	Cooke:HYOP1	1.50
Hydro Run-of-River	Cooke:HYOP2	3.00
Hydro Run-of-River	Cooke:HYOP3	3.00
Hydro Run-of-River	Croton:HYOP4	8.40
Hydro Run-of-River	Edenville:HYOP2	11.00
Hydro Run-of-River	Five Channels:HYOP1	3.20
Hydro Run-of-River	Five Channels:HYOP2	3.20
Hydro Run-of-River	Foote:HYOP1	3.30

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Hydro Run-of-River	Foote:HYOP2	3.30
Hydro Run-of-River	Foote:HYOP3	3.30
Hydro Run-of-River	Four Mile Dam:HYOP3	1.80
Hydro Run-of-River	Grenfell Hydro (PPA):HYOP1	0.30
Hydro Run-of-River	Hodenpyl:HYOP1	9.20
Hydro Run-of-River	Hodenpyl:HYOP2	9.20
Hydro Run-of-River	Hydro Plant - STURGI:HYOP4	1.50
Hydro Run-of-River	Loud:HYOP1	2.20
Hydro Run-of-River	Loud:HYOP2	2.20
Hydro Run-of-River	Michiana Hydro (PPA):HYOP1	0.08
Hydro Run-of-River	Mio:HYOP1	2.20
Hydro Run-of-River	Mio:HYOP2	2.20
Hydro Run-of-River	Ninth Street Dam:HYOP3	1.20
Hydro Run-of-River	Norway Point Hydropower Project: HYOP2	4.00
Hydro Run-of-River	Rogers:HYOP1	1.50
Hydro Run-of-River	Rogers:HYOP2	1.50
Hydro Run-of-River	Rogers:HYOP3	1.50
Hydro Run-of-River	Rogers:HYOP4	1.50
Hydro Run-of-River	Sanford:HYOP3	0.00
Hydro Run-of-River	Secord:HYOP1	0.00
Hydro Run-of-River	Smallwood:HYOP1	0.00
Hydro Run-of-River	Webber:HYOP1	2.30
Hydro Run-of-River	Webber:HYOP2	1.00
Hydro Run-of-River	Whites Bridge Hydro (PPA): HYOP1	0.82
Hydro Storage	Hardy:HYOP1	10.80
Hydro Storage	Hardy:HYOP2	10.80
Hydro Storage	Hardy:HYOP3	10.80
Interruptible Load	CEC Interruptible:1	0.00
Landfill Gas	Adrian Energy Assoc. LLC: GTGS3	2.50
Landfill Gas	Brent Run Generating Station: GTGS2	1.60
Landfill Gas	C & C Generating Facility:GTGS3	2.75
Landfill Gas	Grand Blanc Generating Station: GTGS3	3.81
Landfill Gas	Granger Electric Generating Station I: GTGS4	3.04
Landfill Gas	Granger Electric Generating Station II: GTGS5	3.79
Landfill Gas	Ottawa Generating Station: GTGS6	4.57
Landfill Gas	Peoples Generating Station: 1	3.06
Landfill Gas	Seymour Road Generating Station: GTGS2	0.75

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Landfill Gas	Venice Resources Gas Recovery: GTGS2	1.50
Nuclear (existing)	Palisades (CEC):1	803.00
Pumped Storage Hydro	Ludington:PSOP6	1871.70
Steam Turbine Coal	Campbell (CEC):1	260.00
Steam Turbine Coal	Campbell (CEC):2	360.00
Steam Turbine Coal	Campbell (CEC):3	820.00
Steam Turbine Coal	Cobb:4	160.00
Steam Turbine Coal	Cobb:5	160.00
Steam Turbine Coal	Endicott:1	55.00
Steam Turbine Coal	James De Young:3	10.50
Steam Turbine Coal	James De Young:4	20.50
Steam Turbine Coal	James De Young:5	27.00
Steam Turbine Coal	Karn:1	255.00
Steam Turbine Coal	Karn:2	260.00
Steam Turbine Coal	S. D. Warren Co. #1 Muskegon: GEN5	0.00
Steam Turbine Coal	S. D. Warren Co. #1 Muskegon: STCL2	0.00
Steam Turbine Coal	TES Filer City Station:1	60.00
Steam Turbine Coal	Weadock:7	155.00
Steam Turbine Coal	Weadock:8	155.00
Steam Turbine Coal	Whiting (CEC):1	102.00
Steam Turbine Coal	Whiting (CEC):2	102.00
Steam Turbine Coal	Whiting (CEC):3	124.00
Steam Turbine Gas	Cobb:1	68.00
Steam Turbine Gas	Cobb:2	61.00
Steam Turbine Gas	Cobb:3	52.00
Steam Turbine Gas	Karn:4	638.00
Steam Turbine Oil	Karn:3	638.00
Steam Turbine Oil	Recycled Board Division: STOH2	0.00
Steam Turbine Other	Cadillac Renewable Energy: 1	34.00
Steam Turbine Other	Genesee Power Station: 1	35.00
Steam Turbine Other	Grayling Generating Station: 1	36.17
Steam Turbine Other	Hillman:1	16.00
Steam Turbine Other	Jackson County Resource Recovery: 1	0.00
Steam Turbine Other	Kent County Waste-to-Energy Facility: ST2	15.68
Steam Turbine Other	Lincoln Power Station: 1	18.00
Steam Turbine Other	McBain Power Station: 1	18.00
Wind	Mackinaw City: WIOP5	1.80

Table 22: Wolverine Power Supply Cooperative Existing Generation Resources

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Combined Cycle (existing)	Claude Vandyke (Burnips):6	25.00
Combustion Turbine Gas	Claude Vandyke (Burnips):GT8	24.00
Combustion Turbine Gas	Gaylord [WPSC]:GT1	25.00
Combustion Turbine Gas	Gaylord [WPSC]:GT2	25.00
Combustion Turbine Gas	Gaylord [WPSC]:GT3	25.00
Combustion Turbine Gas	George Johnson:GT10	25.00
Combustion Turbine Gas	George Johnson:GT9	25.00
Combustion Turbine Gas	Lowell:GTGS3	3.60
Combustion Turbine Gas	Tower:GT4	25.00
Combustion Turbine Gas	Traverse City:GT	50.00
Combustion Turbine Oil	Beaver Island:GTOL6	0.00
Combustion Turbine Oil	Lowell:GTOL2	2.20
Combustion Turbine Oil	Tower:GTOL3	3.60
Combustion Turbine Oil	Vestaburg:GTGS8	25.00
Combustion Turbine Oil	Vestaburg:GTOL5	7.70
Hydro Run-of-River	Kleber:HYOP2	1.20
Hydro Run-of-River	Saint Marys Falls:HYOP5	19.96
Interruptible Load	WPSC Interruptible:1	10.00
Steam Turbine Coal	Sims:3	66.30

Table 23: Lansing Board of Water & Light Existing Generation Resources

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Hydro Run-of-River	LBWL Small Hydros:HYOP2	1.06
Hydro Run-of-River	Moores Park:HYOP2	1.00
Interruptible Load	LBWL Interruptible:1	12.00
Steam Turbine Coal	Eckert:1	45.63
Steam Turbine Coal	Eckert:2	46.62
Steam Turbine Coal	Eckert:3	50.79
Steam Turbine Coal	Eckert:4	78.23
Steam Turbine Coal	Eckert:5	79.35
Steam Turbine Coal	Eckert:6	77.33
Steam Turbine Coal	Erickson:1	158.53

Table 24: Modeled Unit Retirements Schedule

Plant Name	Unit #	Owner	Retire Year	Capacity MW
COBB	1	Consumers Energy	2013	68
COBB	2	Consumers Energy	2013	61
COBB	3	Consumers Energy	2015	52
MSTERSKY	5	City of Detroit	2015	39
TRNTNCHN	8	Detroit Edison	2015	210
JMSDYUNG	3	Holland DPW	2016	11
CNNRSCRK	16	Detroit Edison	2016	215
WHTNGCEC	1	Consumers Energy	2017	102
WHTNGCEC	2	Consumers Energy	2017	102
WHTNGCEC	3	Consumers Energy	2018	124
STCLAIR	1	Detroit Edison	2018	153
STCLAIR	2	Detroit Edison	2018	162
ECKERT	1	Lansing BWL	2019	46
STCLAIR	3	Detroit Edison	2019	171
STCLAIR	4	Detroit Edison	2019	158
WEADOCK	7	Consumers Energy	2020	155
PRSQISLE[1]	1	Upper Peninsula Power	2020	25
COBB	4	Consumers Energy	2021	160
RVRROUGE	1	Detroit Edison	2021	242
COBB	5	Consumers Energy	2022	160
WEADOCK	8	Consumers Energy	2022	155
RVRROUGE	2	Detroit Edison	2022	247
WYNDTTWY	5	Wyandotte	2022	22
ECKERT	2	Lansing BWL	2023	47
MSTERSKY	6	Cit of Detroit	2023	47
RVRROUGE	3	Detroit Edison	2023	280
ESCANABA	2	Escanaba Municipal	2023	26
KARN	1	Consumers Energy	2024	255
KARN	2	Consumers Energy	2024	260

[1] Presque Isle units 1 and 2 were retired on January 1, 2007

7. Review of Modeling Software

7.1 Overview

Strategist, a computer software system developed by NewEnergy Associates, LLC, supports electric utility decision analysis and corporate strategic planning. The Strategist system consists of the following application modules:

- Load Forecast Adjustment (LFA)
- Generation and Fuel (GAF)
- PROVIEW (PRV)
- Capital Expenditure and Recovery (CER)
- Financial Reporting and Analysis (FIR)

Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly load patterns are recognized. Production cost simulations are comprehensive. Financial analyses are accurate and thorough. Rate-level determinations reflect each utility's customer class definition and cost-of-service allocation factors. The system employs dynamic programming to develop optimal portfolios of resources. Sophisticated screening methodologies are available to develop and refine strategic marketing initiatives, identify market potential, and build portfolios of initiatives.

In Strategist, integrated resource screening and optimization are accomplished within a single system that handles strategic marketing programs, production costing, environmental reporting, capital budgeting and financial, tax, and revenue forecasts on a rate class basis. Using a single, integrated software system for demand and supply side analysis of all resource types makes these studies much more manageable, ensures consistency in data assumptions, and provides credible, auditable results.

Strategist provides a wide variety of standard reports ranging from unit by unit generating statistics to construction project accounting reports and comprehensive *pro forma* financial results. The system includes full input summaries and detailed diagnostics.

7.2 Supply Side Representation

The Generation and Fuel Module simulates power system operation using proven probabilistic methods. It provides production costs and generation reliability measures that are essential to supply and demand planning. The GAF Module fulfills a strategic planning role in that it requires less computer resources than more detailed production costing modules, without sacrificing overall accuracy.

The general capabilities of the GAF include:

- Probabilistic production costing techniques to simulate the effects of forced outages.
- Most module calculations performed seasonally, where seasons are defined in both number of seasons and by number of days per season.
- Sales, purchases, and hydro generation accounted for on a seasonal basis.
- Hour-by-hour transaction schedule defined or simply specified as occurring during peak load hours, low load hours, or randomly.
- Thermal generating units represented by capacity segments.[10]
- Dispatch of thermal units and economy energy performed on a seasonal or annual basis.
- Pumped hydro projects and direct load control programs economically dispatched on a seasonal basis, based on marginal cost.
- Units dispatched to conform to upper and lower limitations on fuel usage.
- Unit dispatch performed on an "as burned" or replacement cost of fuel basis.
- Unit, company and system emissions calculated based on actual runtimes and fuel usage. Emissions allowances purchased or sold on the basis of system performance and the inputs for allowance cost and allowance base for each effluent. The cost of allowances is reflected in the dispatch lambda used in dispatch order decisions.
- Environmental externalities calculated for emissions, emergency energy, and direct load control.
- Multi-company dispatch provided, with interchange accounting for holding companies or power pool simulation.
- Numerous diagnostic reports provided, which document detailed calculations are provided.

The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities and direct load control programs are then economically dispatched based on the constructed marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operations of the thermal generating units within the year are simulated by a probabilistic technique. The results are the production costs and system reliability indices.

System load data is passed in the form of a typical 168-hour weekly load shape to the GAF from the LFA Module. Then, the dispatch of non-thermal resources is performed. The user may specify the order in which these resources are dispatched, or use the following default order:

[10] Each segment may have a distinct heat rate, which may be input as average, incremental, or coefficients of a quadratic input/output equation. Availability is defined for the entire unit; a partial availability may also be input to represent times when a unit may only operate at minimum capacity. The units which are classified as must-run are committed first, followed by enough other units to satisfy a user-input commitment criterion. The remaining units are committed on an economic start-up and dispatch basis, subject to fuel limits and spinning reserve requirements.

1. The transactions (sales or purchases) that are input in the form of hourly values for each season are added to (in the case of sales) or subtracted from (in the case of purchases) the chronological load curves.

2. The transactions that are characterized by seasonal capacity and energy are scheduled. For each sale transaction, the user chooses whether the sale is a valley fill or peak build sale, or is to be applied uniformly to the load curves. For each purchase transaction, the user chooses whether the purchase is a peak shave or valley reduction purchase, or is to be applied uniformly to the load curves.

3. The hydro generating units are dispatched one at a time. Each hydro unit has a minimum (must-run) MW capacity, a maximum MW capacity, and a total energy (MWh) for the season. The remaining load, after steps 1 and 2, is first modified by subtracting from it the minimum hydro generation for every hour. The remaining hydro energy is used for peak shaving. This peak shaving energy is calculated by subtracting the minimum hydro generation from the total hydro energy. The peak shaving capacity is the difference between the maximum MW capacity and the minimum MW capacity of the unit.

4. Pumped storage hydro is scheduled. Storage dispatch is based on the expected generation cost at each hour before storage, pond storage limitations, cycle efficiency, and minimum savings. The storage algorithm works from highest cost hour down for generation and from lowest cost hour up for pumping, reducing the remaining load at high cost hours and increasing the load at low cost hours. This process is performed subject to the minimum savings and pond limit constraints. An option is available for the capacity of storage not used for economic reasons to be used for reliability purposes.

5. Direct load control (DLC) devices are scheduled. The LFA Module provides information on underlying loads that are available for control and DLC dispatch parameters. All DLC devices are dispatched simultaneously, to achieve the greatest possible savings and avoid setting a new peak. However, there is the added flexibility of defining a user-specified order in which the DLC devices will be dispatched. Payback is explicitly considered in addition to contractual constraints such as the maximum number and duration of interruptions for each program.

If several companies are being modeled, non-thermal resources may be dispatched for a specified company or group of companies. This allows modeling of different electricity industry structures, such as a generation company (Genco) and distribution company (Disco) model where the generating company's non-thermal resources will be dispatched to meet the load of the distribution company. This type of logic is also useful for interconnected power systems where a resource should be scheduled based on both market value and native load requirements.

After the dispatch of non-thermal resources is completed, the remaining load is served by thermal generating units. The thermal dispatch is performed on a seasonal or an annual basis as determined by the user for each water year. If annual dispatch is chosen, the modified seasonal load curves are combined into an annual load curve.

Each generating unit may be represented by up to seven incremental capacity segments. Each capacity segment may have a distinct heat rate. A unit may be designated as a must-run unit, in which case its minimum segment is dispatched before any upper segment in the system. Other thermal unit inputs include commission date, retirement date, immature forced outage rate, mature forced outage rate, and partial forced outage rate at the minimum capacity level. Planned maintenance may be explicitly modeled for each generating unit by specifying the start and end dates for each maintenance, or by entering a start date and number of weeks of maintenance in each year. Maintenance may be handled by either derating the unit's capacity or adjusting its forced outage rate.

The widely accepted probabilistic production costing procedure is used to project the operation of each generating unit. The minimum segments of the must-run units are dispatched first, followed by enough other minimum segments to satisfy a user-defined dispatch commitment criterion. The remaining segments are dispatched in an economic order approximating the economic dispatch procedure of a system operator. Sufficient on-line capacity reserves are maintained to satisfy user-defined spinning reserve requirements. Fuel limits are monitored during the thermal unit dispatch. If fuel limits are exceeded, the system modifies the fuel mixtures and/or energy outputs of the generating units, resulting in a departure from economic dispatch. The impacts of economy energy purchases and sales are determined on an economic basis.

After all available resources have been utilized, several reliability indices are determined. Among these are:

- expected hours with negative margin (known as loss of load hours, or LOLH);
- expected emergency energy; and
- reserve margin.

Alternatively, reliability measures can be held constant, so that equivalent capacity benefits for demand side management (DSM) programs may be calculated. The GAF has the ability to calculate the equivalent capacity benefit of an incremental change in load based on a broad reliability measure. This relieves the user of the uncertain task of estimating a capacity benefit which for many DSM programs (e.g. direct load control) may be difficult to measure. This is a significant improvement over the traditional calculation of the impact on the reserve margin (peak hour impact).

Emissions are calculated each season on a unit-by-unit basis. Removal efficiency characteristics of the pollution control devices associated with each generating unit are input. The individual unit results are then aggregated into company and system emissions rates and totals. Emissions cost, whether represented in the form of allowance purchase price, emissions tax, or emissions externalities, is a result calculated from the thermal dispatch. Separate inputs allow any of these types of emissions costs to be included in a unit's dispatch price, if desired.

7.3 Demand Side Representation

The Load Forecast Adjustment (LFA) Module is a multi-purpose tool for creating and modifying load forecasts and evaluating marketing and conservation programs. Using the LFA, a strategic planner may address key issues related to future electricity or natural gas demand and impacts attributed to each customer group. Results from this analysis can be automatically transferred to other Strategist modules to determine production costs, system reliability, cost-effectiveness of marketing initiatives, financing and revenue requirements, and a variety of other indicators affected by loads.

Because availability of load data is often limited, the LFA is designed to process data at the level of detail readily available. Load data is processed in the LFA by user-defined load groups. It is possible to define these load groups as very detailed or very summary in scope. The LFA categorizes group data based on hourly load shapes. Customer groups for which load shapes are not available are processed differently from those with load shapes.

A key feature of the LFA is its ability to accommodate different levels of detail for different categories of load. If load shapes are unavailable or not needed for some customer groups, the user can easily organize the data to allow the LFA to approximate the missing information. For example, a study which analyzes the loss of a large industrial customer may need detailed modeling of only those rate classes affected by the reallocation of costs. Hourly load shapes could be entered for these classes, and the user need only enter peak, energy, and coincidence factors for any remaining classes.

7.4 External Market and Transmission Representation

The Network Economy Interchange (NEI) feature of the GAF helps reduce operating costs for a group of interconnected utilities by developing the most beneficial unit dispatch schedule for the group.

In a situation where there is unlimited transmission capacity between interconnected systems, the interchange process reaches economic equilibrium. At equilibrium, the marginal costs of all systems are virtually identical. To reach the point of equilibrium, the NEI feature performs interchange among interconnected systems in order to levelize the marginal costs. Interchange is economical as long as the difference in marginal cost is greater than the connection charges among systems.

In power systems, particularly large systems covering major geographical areas, unlimited transmission capacities seldom exist, due to physical or contractual transmission limits. To neglect transmission capacity limits is to overestimate the benefit of economy interchange. This problem may not be severe if transmission constraints are not binding. However, in transmission constrained systems, overestimation of economy interchange benefits may distort overall system production costs.

The NEI feature provides a marginal cost based algorithm for economy interchange among connected systems, while considering losses on transmission lines and enforcing transmission limits for all hours. NEI accomplishes this by systematically matching potential buyers and sellers and incrementally equalizing their marginal costs.

The billing and accounting logic of the NEI module reflects the market clearing price of the system. Therefore, if there are no losses, no connection charges, and no transmission interconnection constraints, the marginal cost of the buyer will equal the marginal cost of the seller and the energy generated will equal the energy received. If there are differences between the buyer's cost and seller's revenue, the losses or surplus revenue is split between them based on the transfer point. If a third party is involved, then the losses and surplus revenue are allocated to the buyer, seller, and/or third parties based on their ownership.

After all other load modifications are complete (transactions, hydro, pumped hydro, and direct load control), the GAF implements economy interchange. Interchange results are used to modify hourly loads of the internal companies. The GAF then executes the thermal dispatch for every internal company. If there is more than one internal company, the NEI feature sums company outputs to obtain the pool results.

7.5 Resource Evaluation Process

The PROVIEW (PRV) module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. PROVIEW is integrated with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system or modifying the load through DSM or marketing programs.

The module allows modeling of emissions-related constraints, emissions allowance trading, and emissions reduction alternatives (e.g. scrubbers or fuel switching). These capabilities are used both to develop optimal environmental compliance strategies and to incorporate resource planning.

Programs are screened by using the LFA module in conjunction with the Differential Cost Effectiveness (DCE) module and the GAF module. Programs in the LFA Module database are evaluated one at a time by the DCE and are ranked based on industry standard cost effectiveness measures such as participant cost, utility cost, total resource cost, societal cost, and ratepayer impact measure (average rate) tests. Groups of programs are then developed into portfolios based on the results of the ranking process. The LFA allows detailed treatment of system, class, or end-use loads, enabling users to specify demand side or marketing programs on an hourly basis. Capacity deferral benefits or costs are calculated using the capacity credit logic in the LFA and/or the reliability equalization logic in the GAF. Energy benefits or costs are calculated using a separate GAF production cost model run for each program.

Once portfolios of programs have been developed, the LFA Module is used in conjunction with PROVIEW to perform integrated demand and supply optimization. LFA load groups representing DSM or marketing programs or portfolios of programs are specified as explicit PROVIEW alternatives. In this way, the programs compete on a "level playing field" with supply options. The optimal demand/supply plan is then developed using PROVIEW's dynamic programming capability. In addition to the optimal plan, PROVIEW retains multiple suboptimal demand/supply plans for further scenario and sensitivity analysis.

The final step in evaluation of DSM or marketing programs involves use of the LFA module in conjunction with all modules of Strategist. The capital expenditure recovery module provides the annual capital expenditure impacts of the programs and allows assessment of program costs which are capitalized. The FIR module allows the evaluation of the impact of the programs on average rates, rate increase requirements and timing, and financial performance. The impact of programs on class rates and cross subsidy issues may be thoroughly evaluated in the class revenue module (CRM).

The general capabilities of PROVIEW include:

- Data input structured in a similar manner to Strategist GAF data.
- Provides quick turn-around time by eliminating options that are not feasible and eliminating unnecessary detail.
- Allows for a full enumeration of all combinations of expansion options and/or demand side management or marketing programs through its dynamic programming option. The system can thus be highly rigorous in its determination of a least-cost expansion plan for the entire planning period.
- Production cost calculations performed for each alternative through the execution of the GAF Module. Demand side programs and associated sales impacts are computed through the execution of the LFA Module.
- Uses the economic carrying charge as the capital cost representation during the study period optimization. After the study period rankings have been determined, the plans will be re-ranked over the planning period horizon using actual year by year revenue requirements. If these are not input, then levelized revenue requirements will be used.
- Explicitly handles end effects in determination of the least cost plan. The end effects analysis approximates the capital and production cost of replacing the resulting utility system in kind over the user-input end effects period.
- Provides users one of five objective functions in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost, minimization of total resource costs, or maximization of total unit profitability.
- Evaluates financial performance of any expansion plan optimized by one of the five objective functions. The expansion plans may be re-ranked based on electric revenue, corporate value of the firm, economic value added, earnings per share, or value per share.

- Provides numerous constraints for the user to reduce the number of options to consider. Minimum and maximum number to add, minimum and maximum reserve or loss of load hours, and first year available to add are but a few. PROVIEW can define alternatives as mutually exclusive or inclusive in a year. It can also restrict alternatives to be dependent upon certain other alternatives being in service (e.g. the second unit in a station is dependent upon the first unit having been constructed). PROVIEW also allows options such as phased construction of combined cycle units to be evaluated quickly. Maximum emissions limits can also be specified to reduce the alternatives considered.
- Optimization can be performed for the entire pool when multi-company summation logic is used. PROVIEW allows constraints to be entered at both the system level and for each company in the pool.
- Models the addition of alternatives which are owned by a company other than the company (or pool) which is being optimized when using multi-company logic.
- Allows complete evaluation of suboptimal plans. All plans are saved in PROVIEW's database for subsequent reporting and analysis. The user may specify the ranking of significantly different plans. Significantly different plans are developed as of a certain year of the analysis.
- Explains in detail, using numerous diagnostics how PROVIEW reaches its optimal plan decision.

PROVIEW requires the data supplied by the user to be separated into two sections: the first section characterizes the existing utility system and the other characterizes the potential expansion or marketing initiative options. The existing utility system data set is composed of the Strategist GAF and LFA Module data sets, which are fully described in the GAF and LFA Modules' online help. Briefly, data requirements for the existing system are grouped according to load, hydro unit, transaction, thermal unit, storage unit, fuel type, fuel class, and general parameter data. Data requirements for the existing load forecast are grouped according to load group, load shape, load class, and parameter data.

The data required for the planning alternatives section contains information relating to alternative resources that may be added or marketing programs that may be implemented. Data in this section defines alternative unit characteristics, construction costs, resource addition limits, and resulting system reliability constraints. Alternative option information is specified in a general manner, so that the model can assume that any proposed available option can be commissioned at any time during the study period.

PROVIEW's dynamic programming calculations are summarized as follows:

1. A capital cost table is constructed. This table contains the economic carrying cost for every alternative for each year of the study.

2. Feasible current-year states (combinations of alternatives) are determined by examining every combination of user-defined resource additions or marketing programs. Feasible states are those which meet reliability dependency and tunnel constraints. One-year capital and production costs are calculated and used to

determine the accumulated cost-to-date. Each feasible state description is saved along with the associated accumulated cost-to-date.

3. The module repeatedly analyzes and saves feasible states for each year during the planning period. At the end of this planning period, a matrix of possible states for each year has been constructed. Note that each feasible state in the final year represents the end product of a different expansion plan.

4. Each potential expansion plan is subjected to end effects analysis. The end effects analysis adds to the accumulated cost-to-date the capital and production cost of replacing the resulting utility system in kind, over a user-specified end effects period.

5. The module traces back through the matrix of feasible states to identify the components of both the optimal plan and each sub-optimal plan.

6. All plans are saved in the database. The optimal plan is set up in the LFA and GAF for subsequent analysis and reporting.

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 (SO_2) control, a SCR system for NOx 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
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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 strategy[12] 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

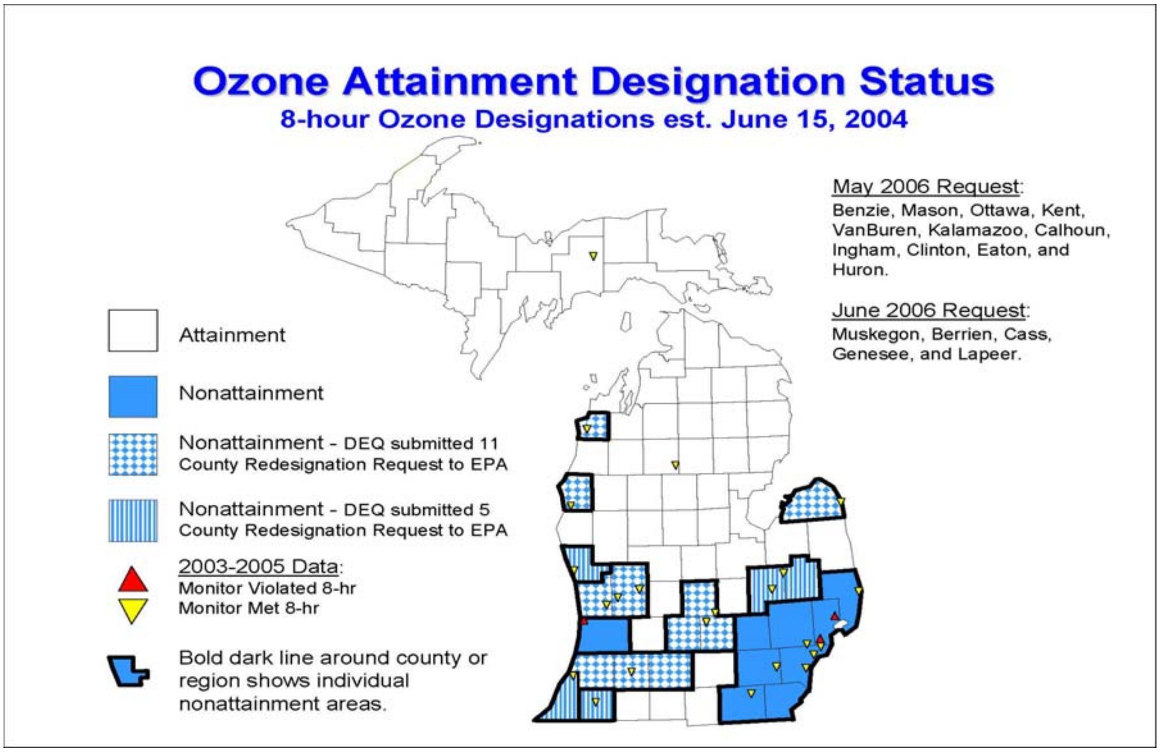
[1] Ultra Critical PC plant was not studied in the CNF.
[2] Base Cost for combustion turbines derived from 2005$ and not 2003$.

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 RACT[13]/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 NOx, 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 SOx, NOx, 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	NOx	Particlate	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 CO_2, 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 CO_2 emissions was sourced from Oak Ridge National Laboratory, U.S. DOE, "Estimates of Annual Fossil-Fuel CO_2 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.

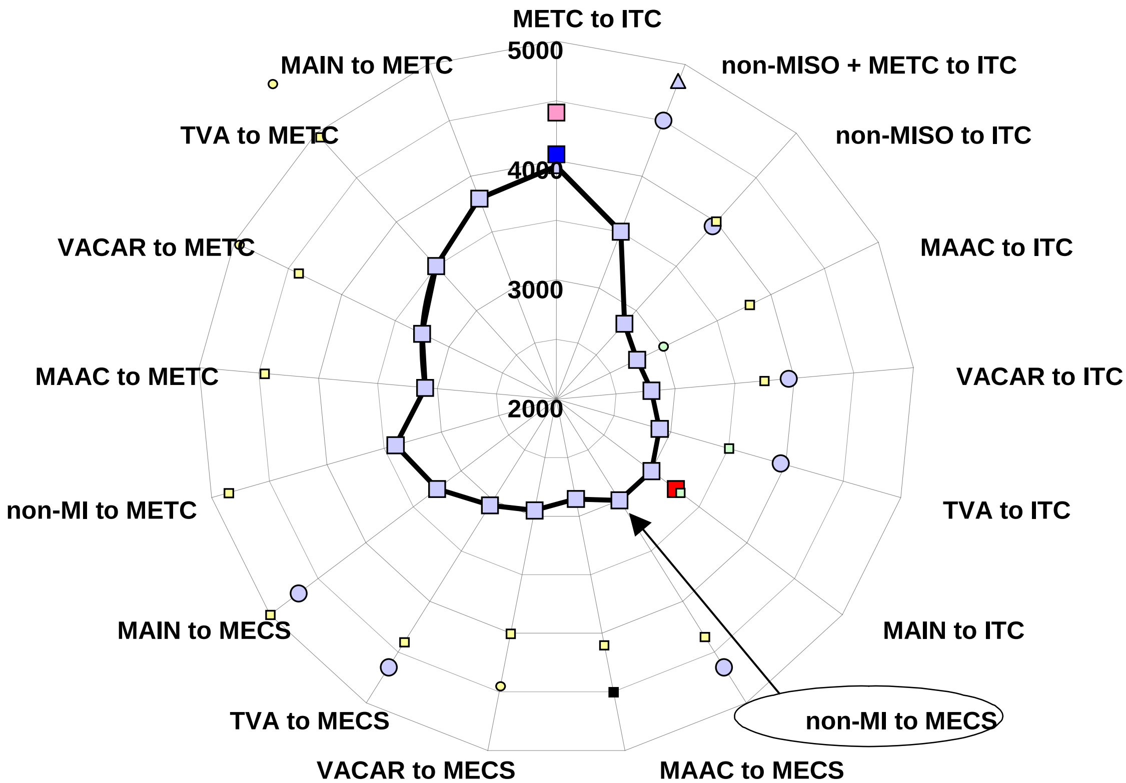
3. Transmission

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 System[4]
2009 Summer -- Total Normalized[1] 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.

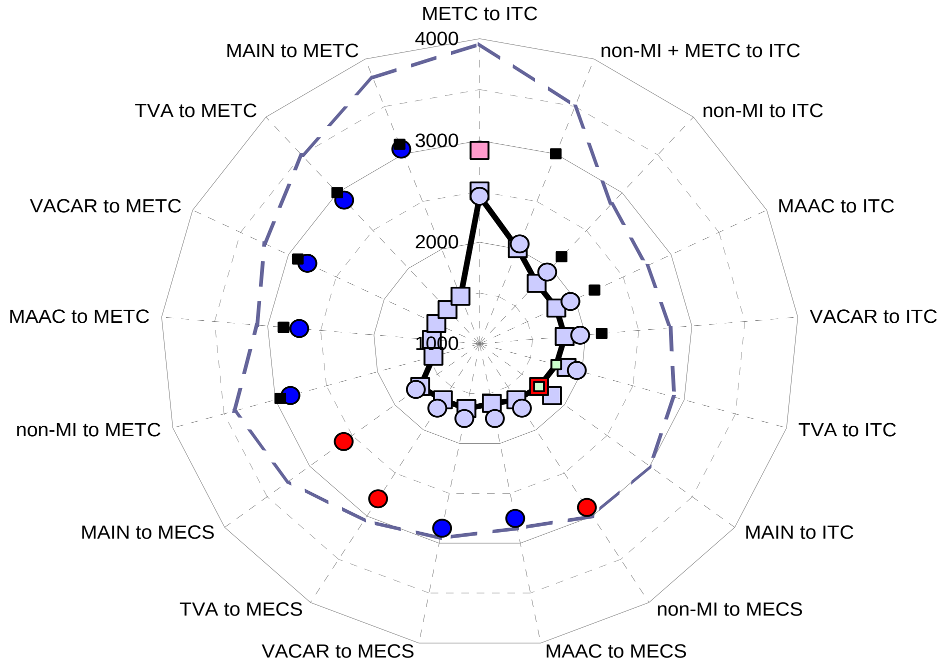
[2] Only the first few limits are shown and the most restrictive limits are shown for groups of limits that are highly correlated. The heavy black line connecting data points near the center of the graph represents the first limit on each transmission interconnection between Michigan's Lower Peninsula 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.

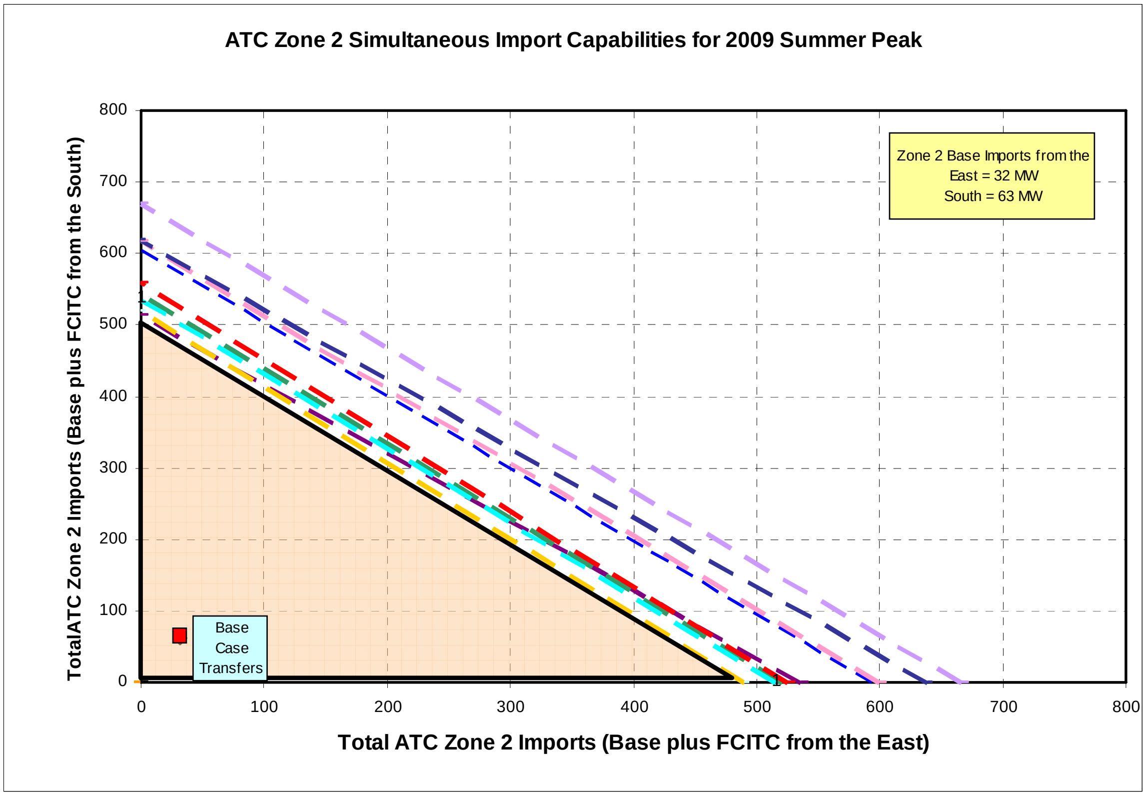
Figure 3: Impact of 1,500 MW Flow from Michigan to Ontario[4]

2009 Summer -- Total Normalized[1] 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 0MSs 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 than is four years longer that 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 MARELLI 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
Assumes no flows to Ontario		
ITC	0.3	1.03
METC	N/A	N/A
MECS	0.02	0.2
Assumes 1,500 MW of flows to Ontario		
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 territory[15] 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 requirements[16] 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.

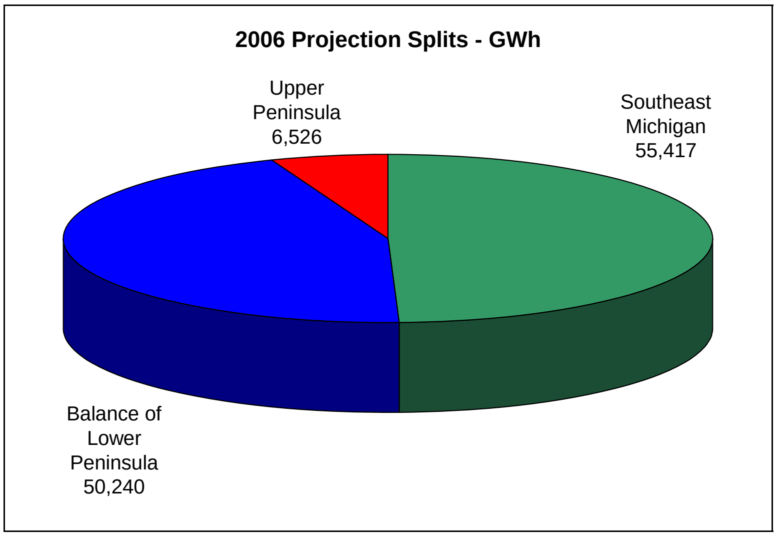
load declined from 2,378 MW in December 2004 to 1,524 MW in December 2005, and Consumers Energy's retail choice load for the same period declined from 926 MW to 552 MW.

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-hour[19] (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

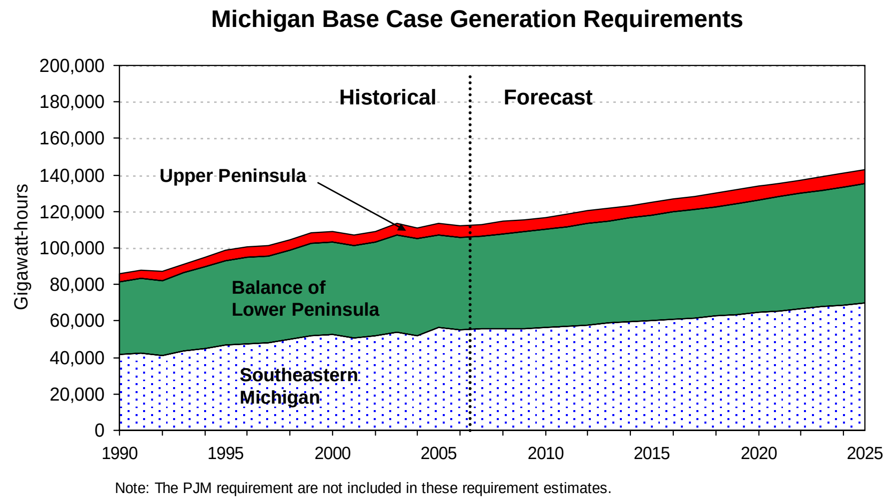


[17] Southeast Michigan is comprised of Detroit Edison, the city of Detroit and the city of Wyandotte.

[18] Balance 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.

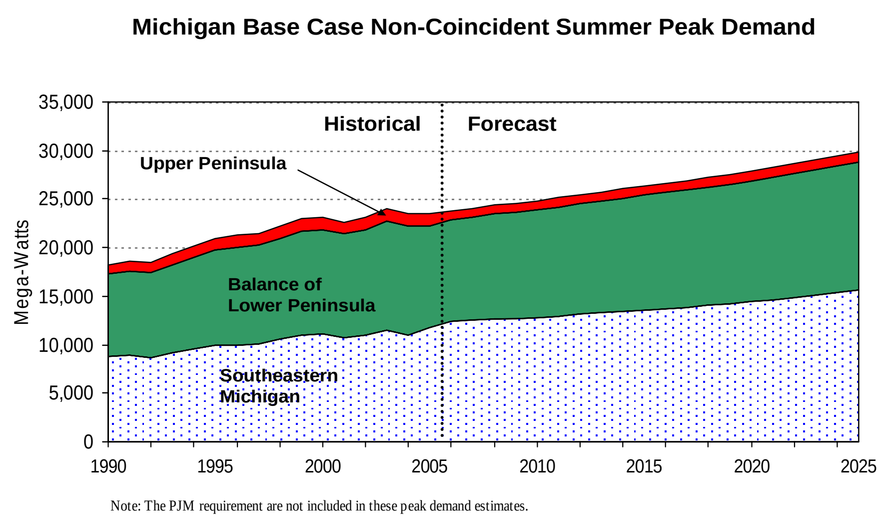
[19] One gigawatt-hour equals one billion watt-hours.

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.

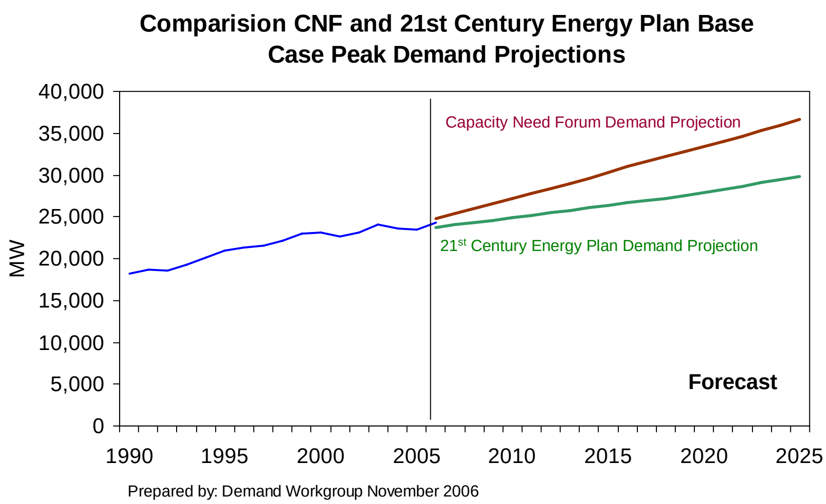
Generally, the Plan outlook as compared to the CNF projection:

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 films 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 PJC 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, 21st 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			
	21st 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, 21st Century Energy Plan, Michigan Public Service Commission			

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

Total Annual Energy Requirements			
	21st 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, 21st Century Energy Plan, Michigan Public Service Commission			

CHAPTER 3

Energy Efficiency Workgroup Resource Assessment

1. Introduction, Methodology and Approach, Overview

1.1 Introduction

Energy efficiency has been aptly defined in the National Action Plan for Energy Efficiency,[26] issued in July 2006: *"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."* The attainment of energy efficiency is a proactive and technology-driven process. It should be distinguished from energy conservation, which 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 always 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. In contrast, energy efficiency is a long-term and capital intensive process yielding long-term benefits to energy consumers. It is the process of replacing new generation resources with end use technology improvements. Energy efficiency can make strong business sense irrespective of economic conditions.

1.2 Methodology and Approach

The 21st Century Energy Plan (Plan) Energy Efficiency Workgroup assessed four major categories of energy efficiency resource options: (1) a statewide energy efficiency program, (2) an electric utility load response program, (3) a commercial building code update, and (4) state specific energy efficiency standards for appliances. Estimates of energy and demand savings, i.e., kilowatt hours (kWh) and kilowatts (kW) respectively, and program costs were developed using a sufficiently rigorous approach for the purposes of developing policy directions. However, actual program development and implementation, including Michigan program funding levels above a minimum program scope will require a more detailed analysis of the Michigan market. In the Policy document, Appendix Volume I, recommendations for an implementation and review process are detailed.

A major goal of estimating energy efficiency potential in Michigan for this report has been to affirm or modify the program scope included in the Capacity Need Forum (CNF) Report. This was accomplished by a statewide energy efficiency study managed by Staff on behalf of the

[26] *The National Action Plan for Energy Efficiency*, issued July 2006, can be viewed online at, http://www.epa.gov/cleanrgy/pdf/ActionPlanReport_PrePublication_073106.pdf.

Workgroup. The resulting estimates were based on a resource modeling format that used "achievable" energy savings potential, as opposed to "economic" or "technical" potential. The distinction between types of estimated impacts is of critical importance. Only achievable potential estimates are useful in establishing actual program scope and funding levels. Achievable potential estimates take into consideration that actual program participation rates will always be less than 100 percent, even though program measures are economic. In addition, achievable potential estimates incorporate time dependence of program implementation, including a program ramp up period, growth phase, and leveling off period. From a technical perspective, modeling customers' behavior occurs through a market adoption curve, where parameters are adjusted to reflect each particular market's expected implementation rate, e.g., slow, moderate or aggressive. Adoption curves like these are used in many industries to forecast market acceptance of new products and programs. In contrast, an economic potential estimate assumes that all efficiency measures with favorable economics will be implemented, and that such implementation takes place by utility customers, both immediately and simultaneously. Economic potential has little value in estimating statewide energy efficiency program scope, in that such a level cannot be achieved in practice. Technical potential is a purely theoretical calculation that is far less conservative than an economic potential, in that cost does not have an impact on the assessment. Neither economic potential nor technical potential were deemed appropriate modeling perspectives for this energy efficiency study.

1.3 Overview

The results of the Michigan energy efficiency potential study described below, 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 projected in load forecasts for the Plan) by more than one-half over a 10 year period and thus reduce the amount of new power generation needed in the state. 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 6,664 gigawatt hours (GWh) to 10,603 GWh. Electric peak demand could be reduced, over the same 10 year period, within a range of 876 megawatts (MW) to 1,889 MW. To achieve savings on this scale, modeling results suggest that annual average programming expenditures would need to be $114 million over the first five years of program operation, and average $146 million over the first 10 years of operation. Using a benefit/cost approach referred to as a utility cost test (UCT), the mean projected levelized cost of energy efficiency programming would be 2.57 cents/kWh, as compared to an avoided electric power cost of approximately 6 cents/kWh.

Not all Workgroup members were supportive of modeling energy efficiency potential using the UCT exclusively. Various other economic tests such as the total resource cost test (TRC), and ratepayer impact measure test (RIM), can be used as a basis for evaluation, and would result in different outcomes when compared to the results of the UCT. These alternate economic tests are discussed in more detail in Section 2 of this chapter.

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. Additionally, peak demand could be reduced by 99 MW. 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 study was undertaken upon the request of the State Energy Office on behalf of the Plan. The Staff estimated that construction cost savings in Michigan would be about $25 million. The results of the energy efficiency and demand response modeling are summarized in Figure 1 and Figure 2.

State appliance standards were investigated, albeit briefly due to time constraints. Estimates made for the Workgroup suggest that if Michigan instituted its own standards on the several appliances that are not currently under federal standards, that significant electric energy savings could be obtained. Additional modeling work will have to be done in order to adequately gauge the costs and benefits. This is discussed in the Policy document, Appendix Volume I.

Figure 1: Plan Energy Efficiency Modeled - Annual Energy Savings (GWh)

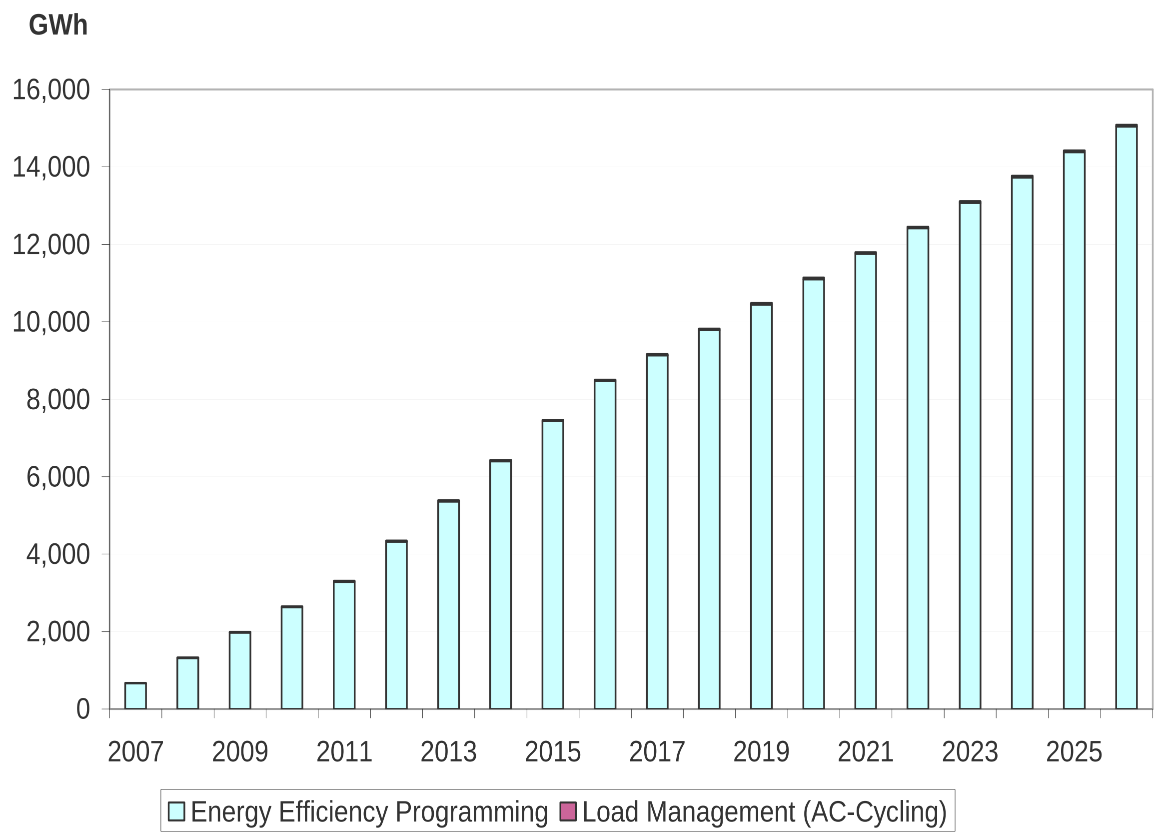
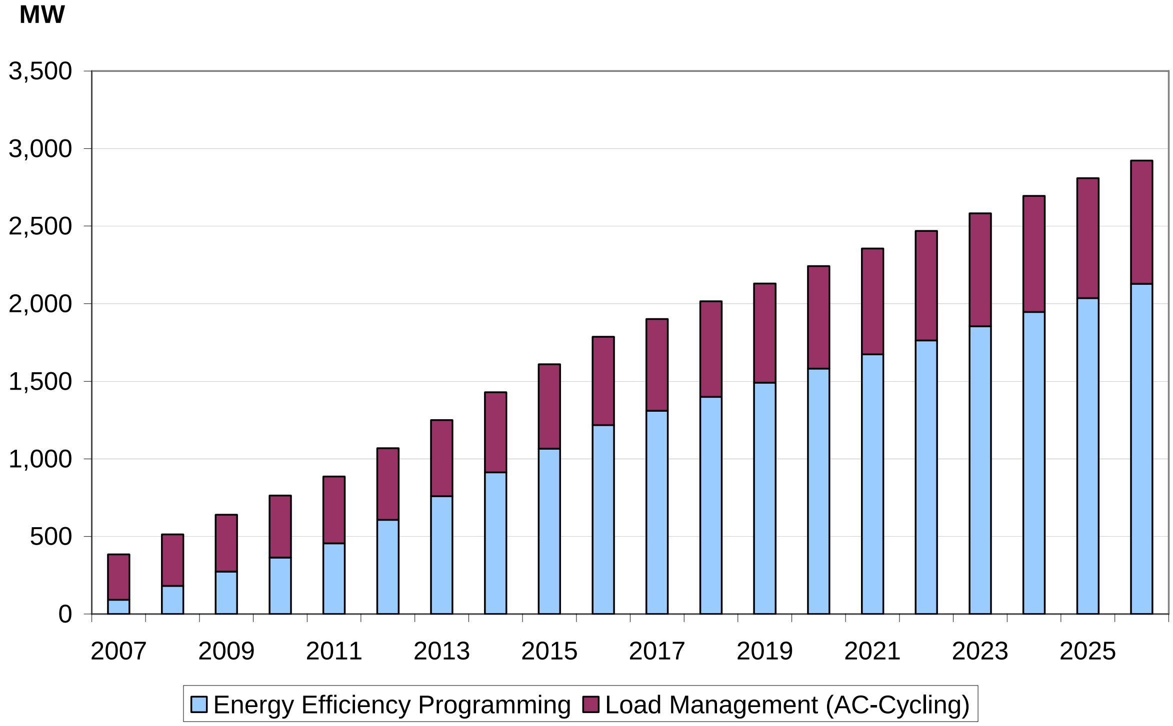


Figure 2: Plan Energy Efficiency Modeled - Peak-Hour Reduction (MW)



2. Energy Efficiency Resource Assessment

2.1 Energy Efficiency

For the CNF, the Demand Workgroup relied upon energy efficiency results from other states that have conducted energy efficiency programs. Extensive data has been collected in these states for several years, and the CNF used this data to estimate the savings that might be available in Michigan. The goal of the Plan's Energy Efficiency Workgroup, in part, was to take a more rigorous approach to estimating energy efficiency. Michigan has not undertaken significant energy efficiency programs in over a decade. Without recent experience or data from Michigan, the MPSC (MPSC or Commission) Staff proposed to model Michigan potential by modifying a recently issued (2005) study for the State of Wisconsin "Wisconsin Model," which was performed by the Energy Center of Wisconsin[26] (ECW). None of the Workgroup participants objected to this approach and several were supportive. A limited number of macro-scale modifications were made to the Wisconsin model in order to account for differences in the scale of Michigan markets and weather patterns that differ between Michigan and Wisconsin. The specific variables used to macro-scale are electric sales by residential, commercial and industrial sectors; population weighted heating and cooling degree days; real discount rate; and avoided cost of power.

Using a Wisconsin model as a basis for a Michigan study was deemed reasonable, since Wisconsin shares important characteristics with Michigan. Wisconsin is a Midwest state having

[26] Energy Center of Wisconsin website can be viewed online at http://www.ecw.org/.

a close proximity to Michigan, with a similar climate and electric use characteristics and a nearly identical commercial building code. In addition, the study was recent, the model reflects the existence of a relatively new statewide energy efficiency program in Wisconsin, and the model is robust in that many of the detailed inputs combine in such a way that scaling can occur at a relatively high (macro) level. The ECW, a non-profit corporation with particular expertise in energy efficiency modeling, was asked to perform the necessary modifications and make the modeling runs on behalf of the State of Michigan.

The ECW's original study for the State of Wisconsin was released in November of 2005. The study was entitled*: Energy Efficiency and Customer Sited Renewable Energy: Achievable Potential in Wisconsin 2006-2015.*[27] The primary objectives of the study were two-fold: (1) to estimate near-term five year and 10 year achievable energy efficiency potential; and (2) to quantify an economically justifiable funding level for a statewide energy efficiency program. These are also two major goals of the Plan. Thus, the ECW was asked by the Staff to translate and scale the original study into a model modified for Michigan.

The original ECW model divided the achievable energy efficiency potential for the state electricity market into manageable segments. The total market was divided into the residential and commercial/industrial sectors. The agricultural market was included in the latter sector. Each sector was subdivided into specifically identified markets. Thirty energy efficiency markets (see Table 1) were included in the ECW study: 15 residential markets and 15 commercial/industrial markets. Each market was classified into three categories of market opportunities: incremental, retrofit, and new construction.[28] In the final analysis, the 30 markets were extrapolated to represent all possible markets on the assumption that the specifically identified markets represented between 75 and 90 percent of the total energy efficiency potential. Of the 30 markets, some were associated with multiple programs. Thus, in all, 38 energy efficiency programs were evaluated for energy efficiency potential.

Demand response programs were not included in the ECW study. The Plan demand response forecast was provided by Detroit Edison and Consumers Energy.

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[27] *Energy Efficiency and Customer Sited Renewable Energy: Achievable Potential in Wisconsin 2006-2015*, online at http://72.36.212.11/prod/236-2.pdf.

[28] *Incremental markets* relate to energy measures that would likely occur at standard efficiency in the absence of program intervention. An example would be the replacement of a burned-out light bulb. The program would induce the replacement with an efficient unit.

Retrofit markets relate to the early replacement of working equipment having a continuing service life, with new high efficiency products. The replacement would not otherwise occur in the absence of program intervention. *New construction markets* are composed of energy efficiency upgrade opportunities in new buildings, which would otherwise be implemented with standard efficiency products.

Table 1: Summary of Energy Efficiency Programs Evaluated for Plan Study

Commercial/Industrial Markets	Residential Markets
High performance new buildings	Consumer electronics
Unitary heating ventilating air-conditioning (HVAC) replacement and system improvements	Compact fluorescent lighting
Lighting remodeling and replacement upgrades	Multi-Family common area lighting
Boiler replacement and systems improvements	Variable speed furnaces
Lighting system retrofit improvements	Central air conditioning
Chiller replacement and system improvements	Multi-Family heating systems
Ventilation system improvements	Room air conditioning
Refrigeration improvements;	Water heater purchases
Motors	New home construction
Compressed air systems	Remodeling
Fan and blowers	Dehumidifier purchases
Pump systems	Direct install market
Manufacturing process upgrades	Shell improvements
Water and wastewater systems	Clothes washer purchases
Agriculture upgrades	Multi-Family fuel-switching

The market characteristics included in the Wisconsin Model were specific to the State of Wisconsin, which has an ongoing statewide energy efficiency program. Michigan markets however, may differ somewhat from the Wisconsin markets. Therefore, actual Michigan program markets would need to be determined via a public hearing process, as outlined in the policy section of this report, prior to implementation of a statewide program.

For each individual energy efficiency market, a baseline of the measure's market was determined. Baseline market share consists of a forecast of naturally occurring implementation of efficiency measures, i.e. implementation that would occur in the absence of program intervention. A "base case" program impact was then developed by subtracting the naturally occurring baseline from the total forecasted market under base conditions. Thus, each base case program represents the net impact of the program, as compared to no program, i.e. the true impact that can be attributed to the program. Base case costs included program administrative costs, market management, field Staff costs, and incentives. Incentives recover a significant portion of the incremental efficiency cost, typically in the range of 50 to 75 percent. The study scales upward each market's base program scope using adoption curves. The study program's scope is increased each year until its marginal cost equals the target avoided cost of power, of approximately 6 cents/kWh, at which point program scope and participation is maximized. If the program does not provide savings at or below the avoided cost, the model attempts to scale the program to optimize the secondary resource, which in most cases is demand savings, at a target avoided peak capacity cost of $80/kW. A Monte Carlo[29] modeling process was used in which repeated random draws of input variables produced a probabilistic uncertainty model. Mean model results were stated in terms of a 90 percent confidence interval.

Modification of the energy efficiency study involved scaling at the sector (residential, commercial, industrial) level to account for Michigan's larger size, rather than scaling individual markets. There are several reasons why translation is not practical at the market input level (30 markets) for purposes of creating a Michigan specific model. Most significant is that Michigan does not have the required detailed data at the market level. The source of much of the required data would come from financial and performance audits of an ongoing energy efficiency program, as well as detailed data obtained in the course of administering and overseeing individual market programs. However, even if a portion of the necessary market level data was available for Michigan, scaling at the market level would not be practical, because data inputs are inter-dependent. For example, market penetration could not be changed without changing the efficiency measure growth rate as well, since such variables are not independent.

Fortunately, the model is sufficiently robust, so that scaling to Michigan can be done at the sector level. The ability to scale to Michigan is related to the characteristics of several key input variables. For example, the key input variables of market penetration and program growth rate are inversely related. This inverse relationship creates stability in programming levels from year to year and is one reason why national data for levelized program costs tends to remain stable over long periods of time. A specific example of how this phenomenon supports sector level scaling can be seen in the residential compact fluorescent light (CFL) market. In this market, Wisconsin has a much higher penetration level (at approximately 12 percent) than the national average of 2 percent. High penetration levels put upward pressure on programming costs in order to maintain market share. On the other hand, high penetration rates are associated with lower growth rates. Michigan, having a relatively untapped CFL market, likely near the national average, would be assumed to have high growth rates consistent with its low market penetration. Since the two variables offset each other, the end result is that Wisconsin CFL market potential can reasonably be scaled to Michigan using only the residential sector electric energy ratios between the two states.

In the commercial and industrial sector, lighting, pumping and compressed air dominate energy efficiency potential. Commercial lighting is highly correlated with the size of the commercial energy sector, thus scaling commercial lighting programs by relative commercial sector energy ratios is justified. With respect to the pumping and compressed air markets, the relative cost and impact between the two markets is similar. On a combined basis, the model is insensitive to the proportion of the industrial end-use market that is related to pumping as opposed to compressed air. Thus, despite the fact that Wisconsin has a higher relative level of pumping, due to a large paper industry, but a lower manufacturing base than Michigan, in which compressed air dominates, the aggregate potential scales by sector energy levels.

[29] Monte Carlo modeling is a computer simulation with a built-in random process, allowing you to see the probabilities of different possible outcomes. Additional information can be found at this link: http://en.wikipedia.org/wiki/Monte_Carlo_Simulation

Michigan and Wisconsin share the same commercial building code foundation, which is the American Society of Heating, Refrigerating and Air Conditioning Engineers, Inc. (ASHRAE) 90.1-1999 Standard. When estimating attainable energy efficiency in the commercial-sector new-construction market, incremental energy savings brought about by program intervention is calculated with respect to the same minimum building standards in both states. Thus, scaling can be accomplished by means of sector energy use without having to make further adjustments.

One note of clarification concerning the interplay between the commercial building code forecast and the energy efficiency program forecast is needed. The Michigan commercial building code forecast assumed an implementation date of 2007, whereas the ECW's energy efficiency potential study assumed that a similar Wisconsin commercial code update would not occur until 2009. Thus, during the initial two years of the energy efficiency potential study, a portion of the energy savings associated with a commercial building code update is also included in an energy efficiency program. The overlap is not likely to be large since the assumed market penetration of a high performance commercial building program (which is one of the energy efficiency markets included in the energy efficiency potential study) is much less than the 100 percent penetration of a statewide building code update, and in addition occurs for only two years of the 20 year forecast period. Nonetheless, in order to avoid double counting when determining the aggregate impact of the combination of an energy efficiency program and an update of the commercial building code, the impact of the energy efficiency program should be offset by such overlap. The energy efficiency program overlap is equal to approximately 5 percent of forecasted electric energy savings, and 7 percent of demand, during 2007 and 2008.

Wisconsin does have a more recent and demanding residential new construction building code than Michigan. This may cause an error to be introduced by the sector scaling. However, the residential building code is primarily focused on natural gas consumption rather than electric consumption. Since the Plan is focused on electric energy use, the error introduced is insignificant, especially at the overall study level, because of the relatively small contribution of the residential new construction market with respect to the total electric energy efficiency potential.

Program costs and impacts can be scaled with a reasonable degree of accuracy by use of the ratio of each sector's electric sales levels for Michigan as compared to Wisconsin. Additionally, climate was adjusted by use of population weighted heating and cooling degree-days. The proportion of program level impacts that are heating or cooling related was applied to the climate adjustment factors. The real discount rate was changed to 6.78 percent plus/minus 2 percent uncertainty. This is a consistent basis used in all Plan modeling efforts. The projected Michigan avoided cost of power, of 6.0 cents/kWh, plus/minus 0.5 cents/kWh uncertainty, was used.

As was stated previously, the ECW's energy efficiency potential model incorporated a Monte Carlo modeling process. Repeated random draws of input variables were used to model related probabilistic uncertainty. Mean results were stated in terms of a 90 percent confidence interval. Similarly, a Monte Carlo modeling process was used by the ECW subsequent to scaling of the Wisconsin Model to Michigan. Thus, Michigan-specific output was represented both in terms of mean results and confidence intervals that represented probabilistic uncertainty. With respect to Michigan energy efficiency program potential, the results indicated that after 10 years of program operation, the projected cumulative mean energy savings was estimated to be 8,474 GWh, within a projected 90 percent confidence interval of 6,664 GWh to 10,603 GWh. The peak electric demand mean-reduction was estimated to be reduced by 1,218 MW, within a 90 percent confidence interval of 876 MW to 1,889 MW. The Michigan-specific energy efficiency results are predicated on the use of a utility cost test (UTC). Figure 3 and Figure 4 illustrate the confidence interval associated with the projected mean energy savings (GWh) and demand reduction (MW).

The results of the Michigan achievable energy efficiency study compare favorably to, and are corroborated by national experience for statewide energy efficiency programs. The Michigan achievable potential study resulted in a levelized cost of conserved energy, of 2.57 cents/kWh, within a 90 percent confidence interval of 2.25 to 2.9 cents/kWh. According to the National Action Plan for Energy Efficiency, programs across the country are demonstrating that energy efficiency can be delivered at a cost of 2 to 4 cents/kWh[30]. In addition, the ACEEE[31] has reported that the national average cost of saved energy lies within a range of 2.3 to 4.4 cents/kWh. The projected mean cost of conserved energy, for the state of Michigan, is within 17 percent of the national average. Although lower than the national average by approximately 0.43 cents/kWh, such lower levelized cost is within the range experienced by states with ongoing energy efficiency programs. Nationally, annual energy efficiency program savings as a percent of total electricity sales lies within a range of 0.1 - 0.8 percent (ACEEE). This measure indicates the relative program effectiveness. The national figures are based upon total reported electricity sales in the various states. Similarly, the results of the 10 year Michigan potential study indicate that the annual expected electricity savings as a percentage of sales would be 0.78 percent.

A final measure of program scope is reflected by the calculation of program funding in terms of mils/kWh. Nationally, public benefit funding levels for energy efficiency programming lie within a range of 0.03 mils/kWh and 3.0 mils/kWh (ACEEE). The 10 year results of the Michigan-specific achievable potential, for the mean case, yield an expected energy efficiency funding level of $146 million per year, which if implemented on a uniform statewide basis, would translate into a public benefits charge, applicable to all Michigan ratepayers, of approximately 1.34 mils/kWh. In contrast, the minimum case yielded a funding level of $68 million per year, or 0.62 mils/kWh.

[30] *National Action Plan for Energy Efficiency*, Chapter 1, page 6.

[31] The American Council for an Energy-Efficient Economy (ACEEE) is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection. See ACEEE website for more information http://www.aceee.org.

Figure 3: Energy Efficiency Program Achievable Potential Electric Energy Reduction 2007-2026

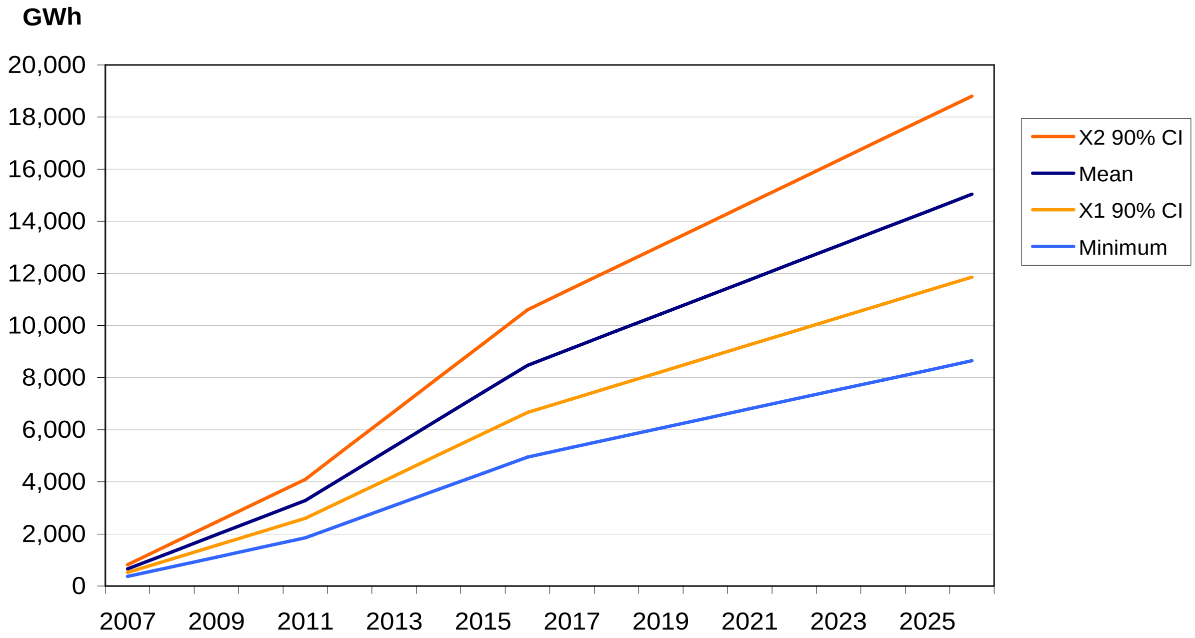
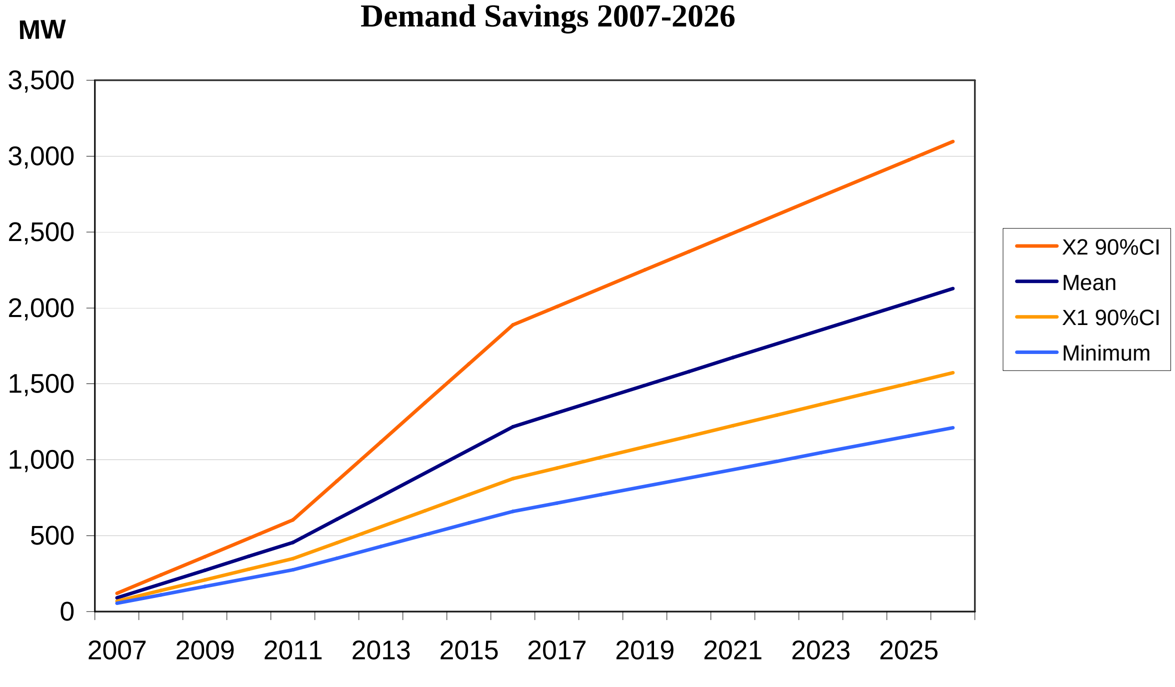


Figure 4: Energy Efficiency Program Achievable Potential, Demand Savings 2007-2026



The mean results of the ECW's Michigan analysis are on the high side of current national experience, comparable to the best performing programs. The ability to achieve a high performing energy efficiency program, (as compared to national experience), will be strongly dependent upon actual program structure and sufficient time for the program administrator(s) to gain competence and expertise. Because utility energy efficiency programming in Michigan ceased more than 10 years ago, a high performing program may be difficult to achieve initially. However, the absence of energy efficiency programming for such an extended period of time has also likely left a considerable amount of "low hanging fruit" within easy reach of a new statewide initiative. It would be necessary to balance these factors if Staff were to recommend a statewide energy efficiency scope for Michigan. For example, it may be prudent to set the initial program funding for a statewide program at a lower level with the goal of increasing the budget as the state gains experience in implementing programs. Such a level should provide a readily attainable program scope that could be increased, over time, with the availability of actual programming data.

As mentioned previously, several benefit/cost tests are available to evaluate energy efficiency programming, including a utility cost test (UCT), a total resource cost test (TRC), a societal cost test (SCT) and a ratepayer impact measure (RIM) test. A recent update of the California Standard Practices Manual, an important source of information on benefit cost tests, identified three of the four tests mentioned above (the Societal test is a variant of the TRC test). The manual helps to understand the cost effectiveness of energy efficiency programs and describes the strengths and weaknesses of each.[32]

- Ratepayer Impact Measure (RIM) test – measures the impact on customer bills or rates due to changes in utility revenues and operating costs caused by the program.
- Total Resource Cost (TRC) test – measures the net costs of energy efficiency programs based on the total cost of the program, including both the participants' and the utility's costs.
- Utility Cost Test (UCT) – measures the net costs of a demand side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits but costs are defined more narrowly.

Each of these tests measures the benefits and costs of energy efficiency from a different perspective and provides useful information for determining the scope and type of energy efficiency programming that may be appropriate for a statewide program. The utility cost and total resource cost tests are the most widely used tests for determining energy efficiency program scope. According to the California Standard practice manual referred to above, the TRC test (and its variant the Societal test), and the UCT test should be compared not only to each other, but to the RIM test as well. However, this multi perspective approach will require the consideration of the tradeoffs (i.e., strengths and weaknesses) of each test.

[32] *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, Governor's Office of Planning & Research, State of California, July 2002.

The UCT and TRC tests both include a utility's avoided generation, transmission, and distribution costs as benefits of an energy efficiency program, but differ in their calculation of costs. Both tests include program administration costs and incentive payments made to participants. However, the TRC test goes one step further by including the participant's incremental costs to purchase an energy efficient measure. Although the TRC test is a more complete measure of the costs incurred by an energy efficiency program, in practice, it does not include all the benefits from such a program, such as reduced maintenance costs.

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, via adoption curves. In this modeling process, the base case program scope for a particular efficiency market is expanded, via adoption curves, until incremental program costs equals the avoided cost of electric power. The amount of program costs, however, is dependant upon the chosen benefit/cost test. Choosing one of the more inclusive benefit/cost tests will have the effect of loading the model with additional program costs, thereby causing the incremental cost of program expansion to equal avoided costs more quickly. The end result is that maximum program scope will be curtailed at a lower kWh level. The Michigan energy efficiency potential study incorporated a utility cost test. Importantly, incentives were modeled to include a significant portion of the efficiency measure cost, typically between 50 and 75 percent. If a total resource cost basis had been used for the energy efficiency potential study, a lower achievable potential estimate would have resulted. However, since the levelized program cost, of 2.57 cents/kWh, is less than half of the avoided cost of electric power, of 6 cents/kWh, Staff does not anticipate that the difference produced by the two tests would cause a major change in program scope.

The Plan did model the impact of energy efficiency in a low case sensitivity scenario, referred to as the low penetration sensitivity. This scenario incorporated the "minimum" achievable energy savings of the Monte Carlo distribution results. The minimum Monte Carlo output can be considered approximately equivalent to the low side of the 95 percent confidence interval. Additionally, the low case sensitivity scenario doubled the levelized, per kWh, cost of saved energy (5.14 cents/kWh). Energy efficiency savings associated with the minimum case were approximately equal to those used in the last year's CNF modeling effort, and more closely approximated national experience.

The savings estimates total 660 MW and 4,952 GWh after 10 years of programming. These compare to 654 MW and 4,991 GWh that were used in the CNF. One of the major goals of the Workgroup was to confirm that the CNF estimates for energy savings and costs were reasonable and the analysis in this study provides a high degree of confidence that the CNF savings and costs were reasonable for planning and programming purposes. In fact, the findings in this report suggest a broader scope would also provide more cost effective benefits for Michigan. The scope of this programming will be addressed in the Policy document, Appendix Volume I. Figure 5 and Figure 6 illustrate the demand reductions and energy savings associated with the low case sensitivity scenario.

Figure 5: Plan Low Penetration Scenario - Peak-Hour Reduction (MW)

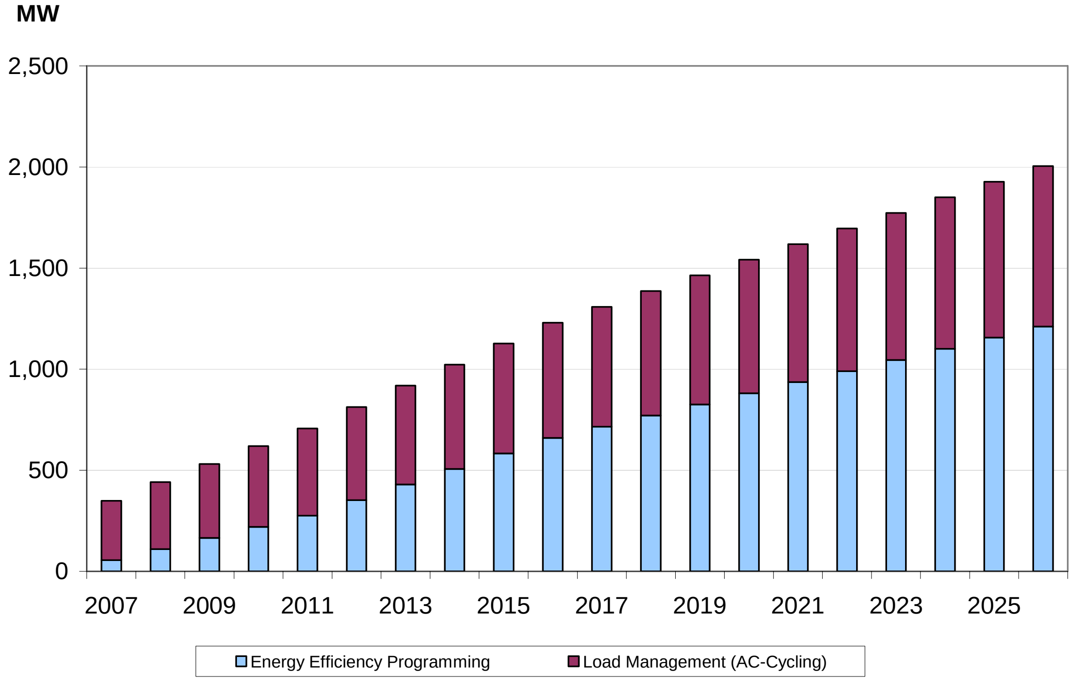
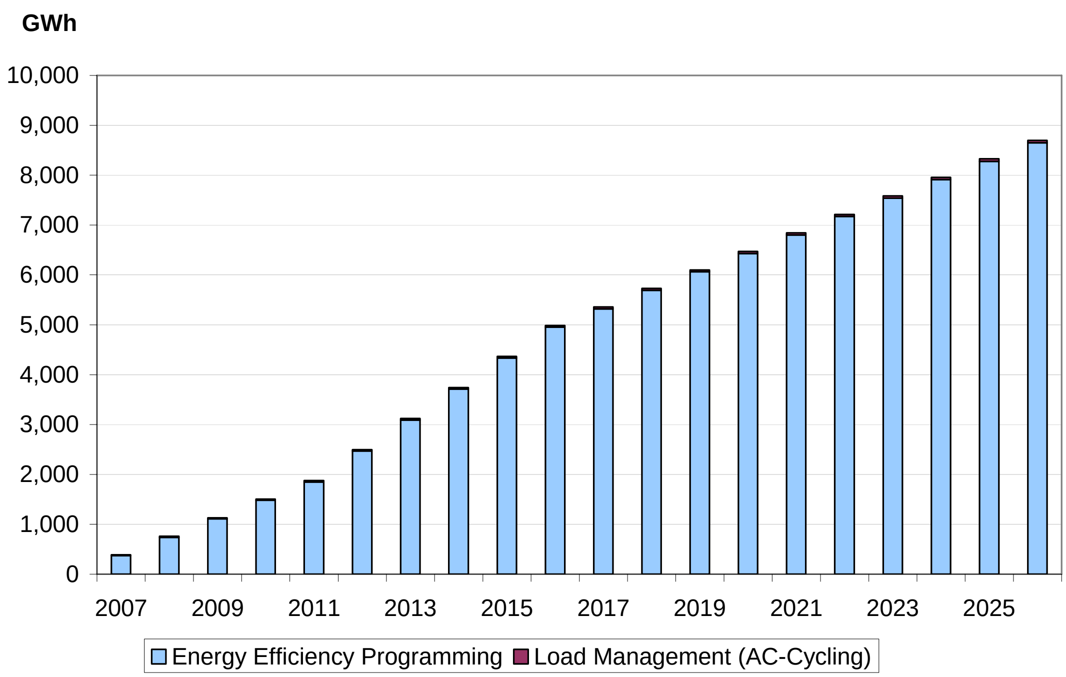


Figure 6: Plan Low Penetration Scenario
Annual Energy Savings (GWh)



2.2 Demand Response Programs

Statewide Utility Load Response programs were extensively analyzed by the Energy Efficiency Workgroup. The concepts of a statewide smart meter implementation and smart rate programs were discussed as resource options. These would include both active load control programs and time-of-use (TOU) rates. However, with respect to modeling of resource potential, only a limited study was performed, including a residential and small commercial air conditioning (AC) cycling program. The peak demand reduction estimates developed for modeling demand response should be considered conservative, and exclusive of demand reductions that could be available using new technologies. It should be noted that an expanded residential and small commercial AC cycling program is a high impact, low cost program, and perhaps the best opportunity for near-term reductions in peak demand. Demand response can be considered a reliable and valuable resource. One factor that should be noted with respect to demand response resource estimates is that unlike traditional power generation resources, reserve requirements are not necessary.

Expanded, active load control resource estimates were developed by Consumers Energy and Detroit Edison, and combined to yield the statewide total. Demand response estimates for Michigan cooperatives and municipal utilities were excluded.

Edison has a sizable existing residential AC cycling program, with over 284,000 customers currently participating. The company's residential air conditioning saturation is 76 percent, with 1.5 million central air conditioners. The potential market consists of the 1.2 million customers not on the current interruptible tariff. For modeling purposes, the assumption was made that an expanded program will replicate Detroit Edison's current interruptible AC program, with a customer take-rate of 3 percent annually. This yields 18,000 new customers per year. It was also assumed that a realistic maximum participation rate would occur at approximately 50 percent of the potential market, i.e., 600,000 customers. Central AC cycling occurs at 15 minute intervals, 15 minutes on, 15 minutes off. The demand reduction per customer is 0.9 kW. The results of the study indicate that after 10 years of program expansion, 162 MW of peak demand reduction would be available, in addition to 255 MW of existing program capacity, for a grand total of 417 MW. Annual direct costs are estimated as $2,970,000, with $14,848,000 of incentives (at 2 cents/kWh during June through October) for a total annual cost during the 10th year of programming of $17,818,000. For purposes of modeling input for the Plan 2025 forecast, extrapolation of the program for a further 10 year period assumed that the maximum cumulative participation rate of 50 percent of the potential market would be reached, adding 316,000 new central air conditioners to the program. The results indicate that 284 MW of peak demand reduction would be available to Edison, in addition to the 255 MW of existing program capacity, for a grand total of 539 MW. Annual direct costs are estimated as $2,970,000, with $19,200,000 of incentives (at 2 cents/kWh during June through October) for a total annual cost during the 20th year of programming of $23,578,000.

Consumers Energy does not have an existing AC cycling program. Thus, projected demand reductions assume the start up of a new program. Annual incentive payments are much lower than projected for Edison because they do not include payments for an existing customer base. Projections for Consumers include both residential and small commercial customers with central air conditioning. The direct load control program assumes that customers volunteer to have utility installed and operated switches with two-way communication on central AC systems. A mix of three incentive options underlies the demand and cost projections. Customers receive incentives in the form of a $ per ton credit during each of a four month season. AC is cycled no more than 100 hours per year with off intervals for each option not exceeding: (1) 15 minutes in a 30 minute interval; (2) 20 minutes in a 30 minute interval; and (3) 30 minutes in a 30 minute interval. The program's annual take rate is taken to be 1.25 percent of customers with central AC, i.e., 13,080 new units added annually. Annual new customer additions are moderated by a 10 percent drop-off rate of customers added in prior years. This assumption results in an exponential decline in the program growth rate. The results of Consumers' study indicate that in the 10th year of operation, the program will consist of 85,000 customers yielding 151 MW of available peak demand reduction. Annual direct costs are estimated at approximately $2,444,000, with $2,035,000 of incentives (averaging $23.88 per customer) for a total annual cost during the 10th year of programming of $4,479,000. Extrapolation of the program for an additional 10 years yields a projected customer base of 115,000 customers with 215 MW of peak demand reduction. In 2026, annual direct costs are estimated as $2,444,000, with $2,744,000 of incentives (averaging $23.88 per customer) for a total annual cost during the 20th year of programming of $5,188,000. For modeling purposes, it was assumed that the aggregate demand reductions of both Detroit Edison and Consumers Energy were representative of the statewide total.

2.3 Commercial Building Code Update, Lighting Standard

The Energy Efficiency Workgroup determined that updating Michigan's commercial building code for lighting represented a regulatory option that may provide a substantial energy efficiency improvement at a very modest cost. Improvements in lighting efficiency typically show the largest savings impact of any electricity efficiency program, and lighting in the commercial sector represents the dominant end use of commercial sector electricity consumption. Approximately 25 percent of commercial building electricity use is for lighting.[33]

Michigan's current commercial building code refers to the 1999 ASHRAE energy efficiency guidelines. ASHRAE revised its lighting density recommendations in the 2004 revision, AHSRAE Standard 90.1-2004. The 2004 revision forms the basis for the electric demand and energy savings resource assessment.

The ASHRAE 90.1-2004 Standard includes a completely revised set of Lighting Power Density (LPD) values from the 1999 Standard.[34] The LPD values are in watts per square foot, and the LPD standard varies for building and building space types under the ASHRAE Standard. The cumulative impacts of the revised light level recommendations, updated lighting equipment

[33] The 25 percent is a national figure. Michigan would be somewhat higher due to relatively lower air conditioning loads than included in the national average end use breakdown. National average commercial sector electricity end use is included in the U.S. Department of Energy's long-term forecasting model; a breakdown is included in tables from its Annual Energy Outlook, Table 5, at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.

[34] There was an interim update by ASHRAE, in 2001, and this update maintained the 1999 LPD values.

efficiencies, revised light loss factors, and changes in design practice were included in the modeling effort.

The impact of updating Michigan's building code for lighting was assessed by Pacific Northwest National Laboratory under a U.S. Department of Energy grant[35] on behalf of the Michigan Energy Office. The analysis consists of evaluation of 32 different building types. Multiple structures for each of the 32 building types were modeled, to capture variations in individual building size and envelope characteristics. The detailed size and envelope characteristics are based on a national survey of recently constructed buildings. The model results from the detailed analysis of 246 individual buildings that were aggregated to 32 building types.

Results from the Pacific Northwest National Laboratory analysis show there is a significant savings potential from updating the Michigan commercial building code to ASHRAE Standard 90.1-2004 (2004) from Michigan's current code. The analysis shows that 0.39 watts per square foot reduction in electric power density (on a weighted average basis across building types) can be achieved.[36] This represents a reduction of approximately 25 percent in lighting demand compared to the 1999 Standard.[37] Since lighting represents one fourth of electricity requirements for commercial buildings, a code update can achieve a better than 6 percent reduction in commercial building electricity requirements.

In addition, due to fewer number of fixtures required to meet the new and reduced ASHRAE lighting level recommendations, updating to the 90.1-2004 Standard actually reduces expected construction costs for 28 of the 32 building types analyzed.[38] Across building types, the reduction in equipment costs for new construction is estimated to be $0.63 per square foot.

Estimates of the per square foot peak demand savings and annual electricity savings were made for the Plan. For peak demand savings, it was assumed that commercial lighting is on at times of system peak demands, and as a result, the 0.39 watts per square foot reduction occurs on peak.[39] This is equivalent to 390 watts (0.39 kW) on a per thousand square foot basis. Energy savings are based on an assumed use of eight hours per day, five days per week, and 52 weeks per year. The 0.39 kW per thousand square foot electric demand reduction translates into an annual electricity savings of 811 kWh per thousand square foot of building space.

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[35] *Michigan State Code Adoption Analysis: Cost-Effectiveness of Lighting Requirements* – ASHRAE/IESNA 90.1-2004, E.E. Richman, Pacific Northwest National Laboratory, September 2006, prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830.

[36] This assumes the building mix in Michigan is essentially similar to nationwide.

[37] The ASHRAE 90.1-2004 lighting power density changes are a significant lowering of lighting wattage densities compared to ASHRAE's 2001, 1999, and 1989 recommendations. Indeed, the changes from 1989 to 1999 included raising the LPD for over half of these building types, whereas the 2004 Standard lowers the LPD for 30 of the 32 building types.

[38] The 32 building types analyzed are the 32 building area types covered by the ASHRAE Standard.

[39] While not 100 percent of lighting are on at times of system peak, the reduced lighting load contributes directly to reduced air conditioning load due to less interior heat gain induced by lighting systems. The Workgroup did not attempt to address this interaction.

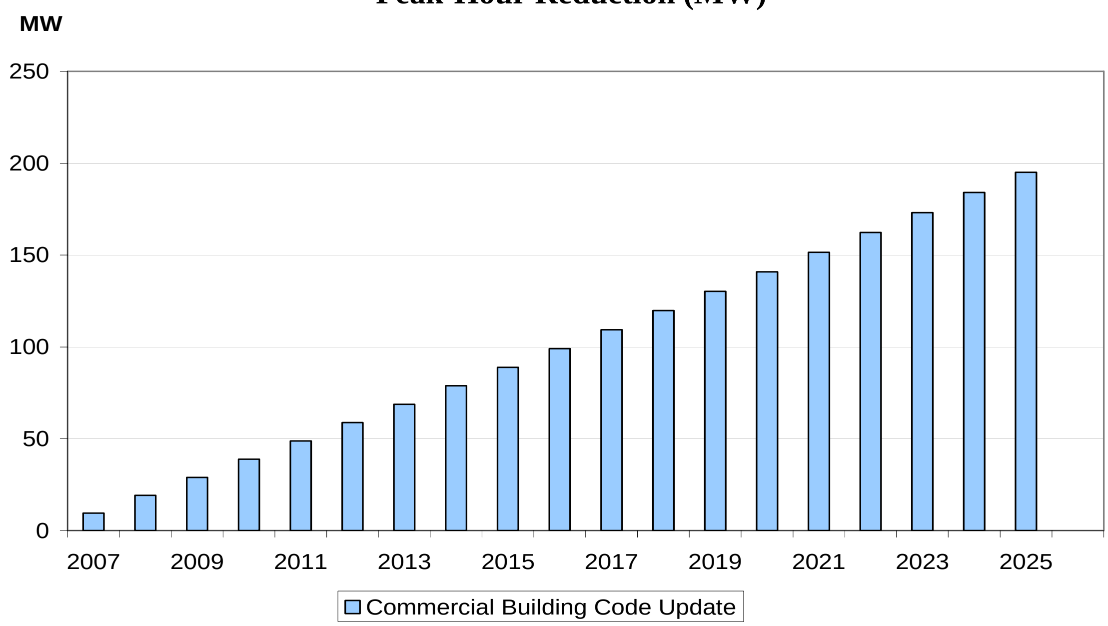
The next step in the modeling process was to convert the demand and energy savings, of 0.39 kW and 811 kWh respectfully, into a statewide total for new commercial construction. The calculation incorporated a projection of Michigan commercial floor space growth made by modifying the Energy Information Administration (EIA)'s National Modeling System Run (aeo2006) to include a growth rate projection for Michigan of 50 percent of the national rate. A base level of Michigan commercial floor space, of 2,238 million square feet was used for the year 2005.

Table 2 illustrates the projected savings from updating the commercial lighting code and Figure 7 and Figure 8, illustrate the projected peak hour demand reductions and energy savings from updating the commercial building code.

Table 2: Projected Electricity Savings: Commercial Lighting Code Update

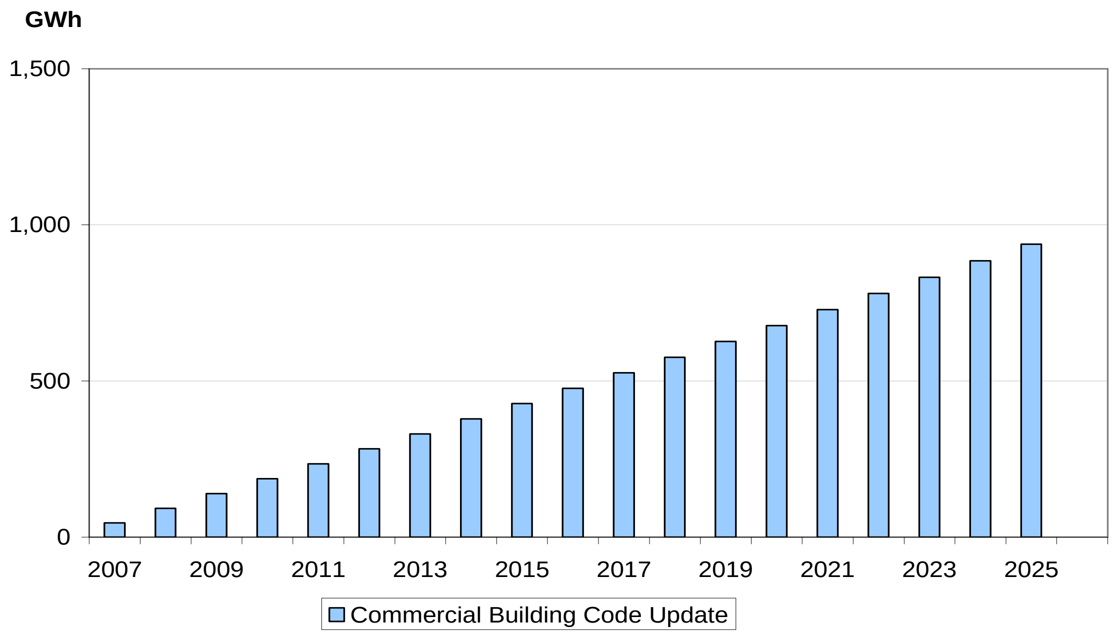
	2007	2016	2025
MW	9 MW	99 MW	195 MW
GWh	46 GWh	477 GWh	938 GWh

Figure 7: Plan Commercial Building Code Peak-Hour Reduction (MW)



Note that the projected electric savings are achievable while actually reducing construction costs by 63 cents per square foot. Michigan's new commercial construction will average about 40 million square feet per year in the projection period, and so the expected construction cost savings would be about $25 million annually.

Figure 8: Plan Commercial Building Code Annual Energy Savings (GWh)



2.4 State Appliance Efficiency Standard

Most major appliances and energy consuming equipment is covered by federal appliance efficiency standards emanating out of the National Energy Efficiency Conservation Act of 1987,[40] the Energy Policy Act of 1992,[41] and the Energy Policy Act of 2005 (EPACT'05).[42] However, even with the expansion of products realized by EPACT'05 (16 new standards with five additional standards to be set by the DOE), federal standards are not all inclusive. According to the report, *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards*[43] issued by the ACEEE and the Appliance Standards Awareness Project (ASAP), in addition to several natural gas fired appliances (which are not being addressed by this report), approximately 10 electric products not covered by federal standards may be appropriate for state regulation in all states, and result in significant electric energy and demand savings. Since the time of the report, March 2006, two of the ACEEE/ASAP recommended products have been subject to proposed DOE rulemaking: these are liquid immersed distribution transformers, and medium voltage dry type distribution transformers. The eight remaining electric products for which standards are recommended for all states are: (1)

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[40] Link to Energy Efficiency Conservation Act of 1987, http://www4.law.cornell.edu/uscode/html/uscode42/usc_sec_42_00006291----000-.html.

[41] Link to Energy Policy Act of 1992, https://energy.navy.mil/publications/law_us/92epact/hr776toc.htm.

[42] Link to Energy Policy Act of 2005, http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ058.109.

[43] *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards*, available online at: http://www.aceee.org/pubs/a062.htm.

bottle type water dispensers; (2) commercial hot food holding cabinets; (3) compact audio products; (4) DVD players and recorders; (5) metal halide lamp fixtures; (6) single voltage external alternating current to direct current power supplies; (7) state-regulated incandescent reflector lamps; and (8) walk in refrigerators and freezers. In addition, among several standards that may be appropriate for particular regions of the country, two may be recommended for Michigan, these are portable electric spas, and residential furnace fans. The ACEEE/ASAP analysis concluded that the aggregate energy savings associated with the recommended state standards, if implemented nationally, would be about 20 percent of the impact of all federal standards. Exclusion of electric distribution transformers covered by proposed federal rules would lower the aggregate savings estimate vis-à-vis federal standards from 20 percent to approximately 16 percent.

The ACEE/ASAP March 2006 report is unique in that contains the only available cost/benefit analysis associated with implementing state appliance efficiency standards for Michigan. The report is very recent, and is substantially detailed. The cost/benefit analysis for Michigan was based on an allocation of national estimates for equipment sales, energy use, energy savings and peak demand. The analysis was updated by the ACEEE for purposes of the Plan. In the update, economic savings were based upon an avoided cost of 6 cents/kWh and a 6.78 percent real discount rate. The results of the analysis are summarized in Table 3.

Table 3: Appliance Standards Benefits - Michigan (ACEE/ASAP)

	2007	2015	2025
MW	9 MW	266 MW	531 MW
GWh	402 GWh	1385 GWh	2771 GWh

3. Summary

The Plan's Energy Efficiency Workgroup resource assessment, studied four categories to determine the energy efficiency potential for the state of Michigan. The assessment of these categories resulted in an estimated statewide potential savings shown in Table 4 and Table 5.

Table 4: Total Projected Electric Savings (GWh)

	2007	2015	2025
Energy Efficiency Programming*	611	8382	14948
Load Management (AC-Cycling)	18	35	48
Building Code	46	477	938
Appliance Standards**	402	1,385	2,771
TOTAL	**1,077**	**10,279**	**18,705**
*Energy efficiency program net of building code overlap 2007-2008. **Appliance standards will be updated by the Energy Office.			

Table 5: Total Projected Electric Demand Reduction (MW)

	2007	2015	2025
Energy Efficiency Programming*	85	1205	2115
Load Management (AC-Cycling)	294	569	764
Building Code	9	99	195
Appliance Standards**	9	266	531
TOTAL	**397**	**2,139**	**3,625**

*Energy efficiency program net of building code overlap 2007-2008.
**Appliance standards will be updated by Energy Office.

The State of Michigan has not had a comprehensive statewide utility funded energy efficiency effort in more than 10 years. With that, it is assumed that there is a considerable amount of "low hanging fruit" within easy reach of a statewide initiative. Although preliminary, the work performed by the MPSC Staff and the Energy Efficiency Workgroup, indicates that there is indeed potential for a successful statewide energy efficiency program, and the assessment scenarios discussed in this report are reasonable to use in modeling various resource options for the state and for near-term policy consideration. The Policy document in Appendix Volume I will outline recommendations for a statewide energy efficiency program including details on program development and implementation.

CHAPTER 4

Renewable Energy Workgroup Resource Assessment

1. Introduction, Methodology and Approach, Overview

The general approach used to estimate renewable energy production potential in Michigan for the 21st Century Energy Plan (Plan) was to revisit the assumptions used in the 2005 Capacity Need Forum (CNF) report in order to identify changes that might be called for, based on newly available or more extensive data and analysis. Cost data used in the CNF was updated to account for various inflationary factors presently affecting construction costs. General inflation was estimated at about 3 percent, to reflect the cumulative change from 2005 to 2006. In addition, most renewable resource capital costs were increased by another 10 percent to account for the recent run-up on the costs of steel, copper, concrete, and labor. The cost of wind generators was increased slightly more than this, from $1,200 per kW of installed capacity, excluding transmission interconnection costs, to $1,425 per kilowatt (kW), to reflect the recent price escalation and strong demand for wind turbines throughout the U.S.

The Capacity Need Forum projected a potential for approximately 1,000 megawatts (MW) of new electric power capacity development in Michigan from a combination of renewable resources and cogeneration (also referred to as combined heat and power or CHP). CHP was modeled for the CNF without any direct analysis of the fuel types that might be used to power such systems (e.g., coal, natural gas, or various biofuels). Modeling for the Plan generally verified and refined the CNF assumptions. The updated analysis shows a similar total contribution available from renewable resources, but does not include coal or natural gas-fired CHP. In the Plan modeling, CHP that is likely to be powered by biofuels is analyzed separately from fossil-fuel powered CHP. Table 1 compares the total quantities of renewable resources modeled for the CNF versus the Plan.

Another difference in modeling assumptions between the CNF and the Plan involves the maximum quantities of renewable resources assumed for availability in the various scenarios. In the CNF, estimates of future renewable resources availability (1,149 MW) were not enough to meet a renewable portfolio standard of 7 percent new (total of 10 percent) Michigan electric sales in 2015 and thus were ultimately scaled up for modeling. In contrast, maximum quantities of renewable resources in the Plan were initially considered to be limited at a specific level of MW and megawatt hours (MWh) by the cost estimate associated with the 2016 level of renewable resources included in this report. In the Plan, this level was 7 percent of projected total Michigan electric sales and was based upon several conservative assumptions. In 2017 and future years, the percentage contribution of renewables was maintained at 7 percent by increasing the MW and MWh based on the Plan energy forecast rate of growth, assuming availability of renewable resources to provide the capacity and energy for each subsequent year of the planning period (i.e., through 2025). This analysis is depicted in Figure 2, for years 2007 to 2016.

Many commenters, however, have questioned the conservative nature of the assumptions used to estimate the potential renewable generation available within Michigan. These comments have focused on the wind energy potential included in the estimate of available renewable energy. Commenters have highlighted the American Wind Energy Association's designation of Michigan as the 14th windiest state in the nation, with an estimated technical potential for approximately 25,000 MW of on-shore wind energy. These comments prompted Staff to review and further analyze the assumptions and methodologies used in this study. Based on that review, Staff recommends that an accelerated goal of up to 10 percent of the state's electric energy needs could be met by renewable energy as part of a renewable energy portfolio standard. It appears that sufficient wind resources are available to meet this goal by the end of 2015 instead of 2016. The resource capacity projections for this accelerated portfolio analysis are summarized in Figures 1 and 2, and Figure 3 (p. 144) The energy projections for this accelerated portfolio analysis are shown in Table 3 (p. 126) and Figure 1.

Table 1: Renewable Resources Capacity Projections for CNF and Plan (MW)

Renewable Energy System Type	CNF		Plan	
	Alt-Tech[1] 2015	Scaled-Up[1] 2015	7% RPS Modeled 2016	10% Accelerated RPS 2015
Wind	420	443	525	2,150
LFG	131	138	131	128
Anaerobic Digestion[2]	51	54	82	73
Cellulosic Biomass / CHP (Cogen)[3]	547	576	385	340
Total	**1,149**	**1,211**	**1,123**	**2,691**

[1] In CNF analysis, the Alternative Generation Workgroup presented a set of resource availability projections, as reflected here in the "Alt-Tech" column. In modeling the CNF Alternative Technologies scenario, however, those resource quantities were increased by a few percent in order to model achievement of a 7% renewable portfolio standard. Those increased amounts are shown here in the "Scaled-Up" column.

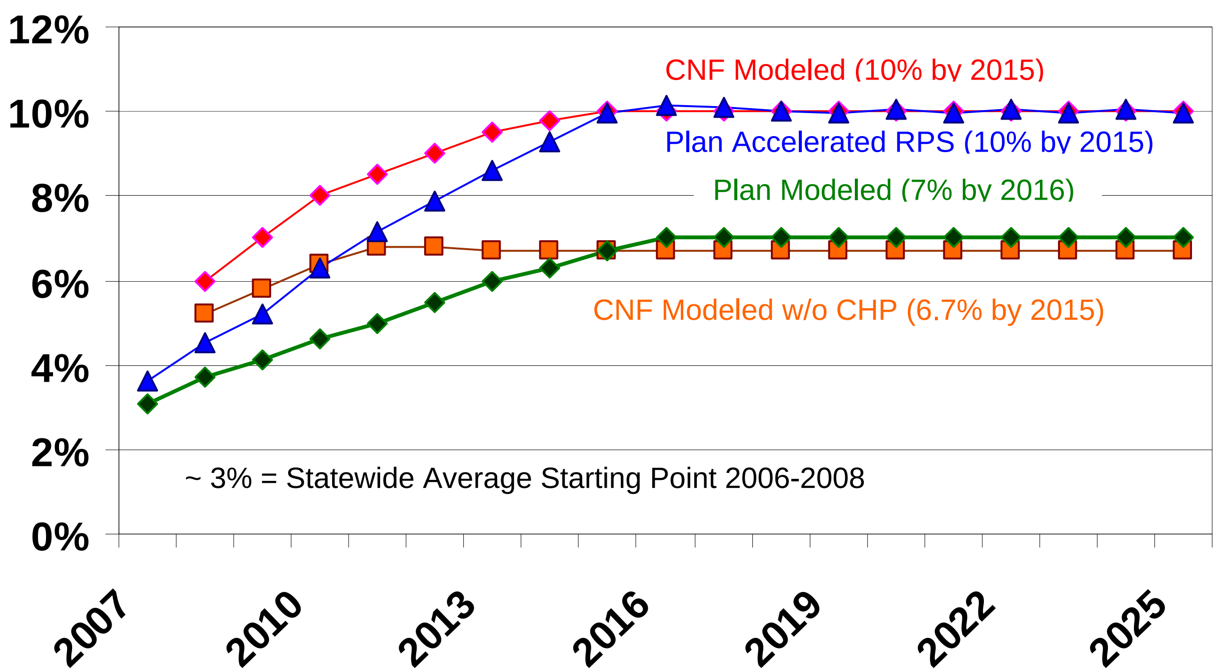
[2] In CNF analysis, anaerobic digestion from cattle was modeled. The Plan modeling includes anaerobic digestion from cattle, wastewater treatment plants, plus swine and poultry operations.

[3] In CNF analysis, cogeneration (also known as Combined Heat and Power, or CHP) was modeled based on the estimated potential at existing large coal-burning industrial boilers in Michigan. The fuel-types considered for cogeneration in the CNF analysis included coal and natural gas. In the Plan modeling, CHP is considered along with other options in the Alternative Technologies Workgroup. The potential for biomass-fired electric power generation systems is presented here. Many such systems would likely incorporate cogeneration technology.

No matter which potential renewable energy estimate is used for developing a portfolio standard, one of the important implications is that the further one projects into the future the more uncertainty clouds the projections. Projecting more than a decade in the future is most difficult given the rapid pace of technological improvements for some renewable energy systems and policy changes that are likely to affect all energy sources in different ways. Considering these uncertainties, Staff is confident that renewable energy sufficient to meet seven to 10 percent of the state's needs can be developed by 2015. Staff also made policy recommendations to assure that no unforeseen events intercede, by which meeting these standards and recommendations would otherwise create an undue burden on utilities and their ratepayers. Staff also recommended reviewing the findings of the Plan every few years, to continuously subject all the assumptions to critical analysis and improve the accuracy wherever practical.

Figure 1 compares the percentage of renewable resources modeled in the CNF, both with and without the inclusion of cogeneration (CHP), with the 7 percent level modeled for the Plan and the 10 percent accelerated renewable portfolio standard (RPS).

Figure 1: Renewable Energy Percentage Projections in CNF, Plan Modeling, and Accelerated RPS



It should be noted that Governor Granholm explicitly directed the Plan to develop a proposal for an RPS, with "targets for the share of this state's energy consumption derived from renewable energy sources." For purposes of establishing a reasonable and achievable renewable energy portfolio standard and modeling the impact of renewable energy, Staff estimated the quantity of renewable energy shown in Table 2 and Table 3 will be available at the estimated costs shown in Table 4 between 2006 and 2016. After 2016, the Plan modeled the quantity of renewable energy to increase only at the same rate as forecast growth.

2. Resource Assessment

For the analysis completed for the Plan, the definition of renewable resources was based on 2000 PA 141, Section 10g(1)(f) (MCL 460.10g(1)(f)). That section indicates renewable energy source means "energy generated by solar, wind, geothermal, biomass, including waste-to-energy and landfill gas, or hydroelectric."

Approximately 3 percent of the electric energy currently sold to Michigan utility customers is generated by renewable energy sources. Table 5 (p. 128) shows the renewable energy contributions used to meet Michigan utility needs in 2005, when the statewide average was about 3.0 percent.

For purposes of the Plan, biomass electricity production was modeled from five major sources: (1) combustion of cellulosic biomass, including forestry and agricultural residues; (2) anaerobic digestion for wastewater treatment plants; (3) anaerobic digestion for cattle; (4) anaerobic digestion for swine and poultry; and (5) landfill gas. Wind energy production from utility-scale wind generators was also modeled.

Table 2: Capacity Projections for 7 and 10 Percent Renewable Portfolios (MW)

Year	Modeled 7% RPS					Accelerated 10% RPS	
	Landfill Gas	Anaerobic Digestion	Cellulosic Biomass	Wind	Total	Wind	Total[1]
2006	0	0	0	0	0	0	0
2007	24	4	0	10	38	239	267
2008	47	11	41	87	185	478	577
2009	71	18	81	88	258	609	779
2010	94	24	122	119	358	956	1,196
2011	118	30	162	154	464	1,194	1,504
2012	120	43	207	272	642	1,433	1,803
2013	123	53	251	360	787	1,672	2,099
2014	126	64	296	410	896	1,911	2,397
2015	128	73	340	465	1,006	2,150	2,691
2016	131	82	385	525	1,123	2,150[2]	2,748
2017	134	83	392	535	1,144	2,150	2,759
2018	136	85	401	546	1,168	2,150	2,772
2019	139	87	410	559	1,194	2,150	2,786
2020	142	89	419	571	1,221	2,225	2,875
2021	145	91	428	583	1,246	2,225[2]	2,889
2022	147	93	437	595	1,271	2,300	2,977
2023	150	95	446	609	1,299	2,300[2]	2,991
2024	153	97	456	622	1,328	2,375	3,081
2025	155	99	465	634	1,354	2,375[2]	3,094

[1]Landfill gas, anaerobic digestion, and cellulosic biomass quantities are unchanged for the accelerated RPS.

[2]Wind capacity remains the same some years after 2015 because biomass resource types were all projected to continue to increase from 2016 through 2025 at the same rate as forecast demand. Thus, in order to maintain the RPS as close as possible to a constant 10%, wind capacity growth was modeled at 75 MW increments every few years. See also Table 3.

Solar electricity production was not explicitly modeled for the Plan since it has experienced only limited market penetration in Michigan at this time. Although larger scale production and continuing technological improvements are likely to make solar applications more attractive in the future, Staff does not anticipate sufficient market penetration in the near-term to substantially change the modeling assumptions. Staff plans to continue to review the attractiveness of adding solar generation technology to the renewable resource mix, for modeling purposes in the future.

Table 3: Energy Projections for 7 and 10 Percent Renewable Portfolios (GWh/year and Percent of Total Generation Requirements)

Year	Plan Forecast	Existing Renew-able	7% by 2016 RPS Renewable Resources Modeled (GWh/year)						10% by 2015 Accelerated RPS (GWh/year)		
			Landfill Gas	Anaerobic Digestion	Cellulosic Biomass	Wind	Total New Renew-able	RPS %	Wind	Total[1] New Renew-able	RPS %
2006	112,183	3,279	0	0	0	0	0	2.9%	0	0	2.9%
2007	113,021	3,279	189	28	0	25	242	3.1%	586	803	3.6%
2008	114,492	3,279	370	74	284	213	942	3.7%	1,172	1,900	4.5%
2009	115,411	3,279	560	123	568	216	1,467	4.1%	1,494	2,745	5.2%
2010	116,902	3,279	741	165	853	292	2,051	4.6%	2,344	4,103	6.3%
2011	118,442	3,279	930	207	1,135	378	2,650	5.0%	2,930	5,202	7.2%
2012	120,245	3,279	946	304	1,448	667	3,365	5.5%	3,516	6,214	7.9%
2013	121,685	3,279	970	372	1,760	883	3,985	6.0%	4,102	7,204	8.6%
2014	123,396	3,279	993	448	2,073	1,006	4,520	6.3%	4,688	8,202	9.3%
2015	125,023	3,279	1,009	509	2,386	1,141	5,045	6.7%	5,274	9,178	10.0%
2016	126,811	3,279	1,033	572	2,698	1,288	5,590	7.0%	5,274[2]	9,577	10.1%
2017	128,180	3,279	1,056	582	2,748	1,312	5,698	7.0%	5,274	9,660	10.1%
2018	129,982	3,279	1,072	595	2,807	1,340	5,813	7.0%	5,274	9,748	10.0%
2019	131,775	3,279	1,096	608	2,871	1,370	5,945	7.0%	5,274	9,849	10.0%
2020	133,721	3,279	1,120	622	2,937	1,402	6,080	7.0%	5,457	10,136	10.0%
2021	135,456	3,279	1,143	635	2,996	1,430	6,204	7.0%	5,457	10,231	10.0%
2022	137,329	3,279	1,159	648	3,059	1,460	6,326	7.0%	5,641	10,507	10.0%
2023	139,226	3,279	1,183	662	3,127	1,493	6,465	7.0%	5,641	10,613	10.0%
2024	141,266	3,279	1,206	677	3,197	1,526	6,607	7.0%	5,825	10,905	10.0%
2025	143,094	3,279	1,222	691	3,261	1,556	6,730	7.0%	5,825	10,999	10.0%

[1]Landfill gas, anaerobic digestion, and cellulosic biomass quantities are unchanged for the accelerated RPS.

[2]Wind energy remains the same some years after 2015 because biomass resource types were all projected to continue to increase from 2016 through 2025 at the same rate as forecast demand. In order to maintain the RPS as close as possible to a constant 10%, wind capacity growth was modeled at 75 MW increments every few years.

Table 4: Renewable Energy Cost Estimates

	Landfill Gas at New Facilities	Landfill Gas at Existing Facilities	Anaerobic Digestion Animal Waste[1]	Cellulosic Biomass	Wind
Capital Installed Cost ($/kW)	$1,356	$1,130	$2,825	$1,900	$1,425
Capital Recovery Rate (%/year)	14%	14%	14%	14%	14%
Annual Operating Hours	8,760	8,760	8,760	8,760	8,760
Capacity Factor (%)	90%	90%	80%	80%	28%
Efficiency (Btu/kWh)	10,000	10,000	10,000	16,500	n/a
Fuel Costs ($ per million Btu)	$1.85	$1.85	$0	$1.75	$0
Resulting Costs ($ per kWh)					
Capital Recovery	0.024	0.020	0.056	0.038	0.081
Fuel	0.019	0.019	0.000	0.029	0.000
PTC (10 years only)[2]					-0.019
O&M	0.0309	0.0309	0.02575	0.002	0.01
Total[3]	**0.074**	**0.070**	**0.082**	**0.069**	**0.072**

[1] Fuel costs are shown as zero. It should be noted that the residue that remains after anaerobic digestion usually can be land applied as a fertilizer and soil amendment. Thus, there may be some residual value to more than offset any costs associated with delivering waste materials to an anaerobic digester.

[2] The Federal Production Tax Credit (PTC) for wind power was originally enacted as part of the Energy Policy Act of 1992 and was first scheduled to sunset on June 30, 1999. The PTC has been extended by Congress four times. The most recent extension, in the Energy Policy Act of 2005, is through December 31, 2007. (See footnote 64, on p. 142.) The PTC provides a 1.9-cent per kWh incentive for the first 10 years of operation.

[3] Costs do not include interconnection costs.

Systems that produce thermal energy rather than electricity were not explicitly modeled, though they may be already cost effective in some applications and could make contributions to meeting the state's future energy needs. These systems might include a wide variety of biomass-fueled heating appliances, solar water heaters, and other sources but are more likely to displace natural gas than electric applications.

Michigan has benefited for many years from relatively inexpensive hydroelectric power with some hydroelectric plants in operation for 100 years. Based on a national hydroelectric resource assessment conducted by the Idaho National Laboratory, Michigan is estimated to have additional hydroelectric power development potential of 133 megawatts, on average (MWa), of feasible low power (< 1MWa) or small (>= 1 MWa and <30 MWa) units.[44] It is also possible that existing hydropower plants might be modified to increase efficiency and electric generation output. At the time of writing this report and preparing data for modeling, not enough specific information about the cost and permitting issues of new hydropower and upgrades of existing hydropower is known. As a result, additional hydropower resources were not modeled as part of

[44] See http://hydropower.inel.gov/resourceassessment/pdfs/main_report_appendix_a_final.pdf, *Feasibility Assessment of the Water Energy Resources of the Untied States for New Low Power and Small Hydro Classes of Hydroelectric Plants*. MWa means average MW production.

the Plan. While Staff did not estimate the potential energy available from these options nor factored in potential siting and construction issues, at least some additional hydroelectric power resources may be available to satisfy RPS targets by load serving entities in Michigan.

Table 5: Michigan Utility Renewable Energy Sales Source Percentages (2000-2005)

Company	Percentage of Renewable Sources, by Year					
	2000	2001	2002	2003	2004[1]	2005
Alger Delta Co-op	n/a	n/a	n/a	n/a	n/a	11.0[2]
Alpena Power	11.2	13.0	13.3	11.4	12.5	8.1
American Electric (Indiana Michigan) Power Co.[3]	n/a	0.7	0.7	1.0	1.0	0.4
Cherryland Electric Co-op	n/a	n/a	n/a	n/a	n/a	1.2
Cloverland Electric Co-op	49.7	45.5	45.3	43.0	46.3	52.4
Consumers Energy	3.8	4.8	4.6	4.5	5.0	4.5
Detroit Edison	n/a	1.4	1.4	1.2	1.1	1.1
Edison Sault	42.0	38.3	39.5	37.1	39.5	39.3
Great Lakes Energy Co-op	n/a	n/a	n/a	n/a	n/a	1.2
Midwest Energy Co-op	n/a	n/a	n/a	n/a	n/a	2.5[2]
Ontonagon County REA	n/a	n/a	n/a	n/a	n/a	11.0[2]
Presque Isle Electric & Gas Co-op	n/a	n/a	n/a	n/a	n/a	1.2
Thumb Electric Co-op	n/a	n/a	n/a	n/a	n/a	1.0[2]
Tri-County Electric Co-op	n/a	n/a	n/a	n/a	n/a	1.2
Upper Peninsula Power Co. [4]	12.0	12.0	17.0	12.0	11.0	9.7
We Energies	n/a	2.0	2.4	2.2	2.2	1.8
Wisconsin Public Service Corp.	2.1	2.2	2.6	2.8	2.9	2.8
Wolverine Electric Power Co-op[5]	n/a	1.1	0.7	0.9	1.2	1.2
Xcel Energy[6]	13.6	15.3	14.3	13.6	16.1	15.5[2]
Statewide Average[7]	n/a	n/a	n/a	n/a	n/a	**3.0**

[1]In its May 18, 2004 Order in Cases Nos. U-12915 & U-13843, the Commission stated, "[T]he utilities' annual disclosure requirements should accurately reflect that green power customers are paying additional costs for renewable and environmentally-friendly energy and…utilities should not represent in future reports that they are providing these services to all rate classes." (Order, pp. 3-4). Data beginning with the 2004 reporting year, represents percentages of renewable sources for customers who are not participating in special voluntary green rate programs.

[2] Data for year ended March 31, 2006.

[3] Includes hydroelectric and 0.1 percent or less from other renewable fuels. 2003 data did not include hydroelectric.

[4] Upper Peninsula Power Company's renewable energy was impacted in 2003. In May of that year a fuse plug at the Silver Lake reservoir owned by UPPCO was breached. This breach resulted in subsequent flooding downstream on the Dead River, which is located in Michigan's Upper Peninsula near Marquette, and impacted hydroelectric generation. UPPCO has announced its decision to restore Silver Lake as a reservoir for power generation pending approval of a license amendment and an economically feasible design by the FERC. The FERC has required that a board of consultants evaluate and oversee the design approval process. UPPCO is developing a timeline for the project, provided the FERC approves an economically feasible design. Once work is done, Silver Lake is expected to take approximately two years to refill, assuming average precipitation.

[5] Wolverine Power Supply Cooperative is the sole supplier of electric generation service to four of Michigan's cooperative (member-owned) electric distribution companies: Cherryland Electric Cooperative, Great Lakes Energy, Tri-County Electric Cooperative, and Presque Isle Electric and Gas Co-op. Wolverine data for 2003 includes 0.51 percent and 2004 includes 0.66 percent of hydroelectricity. Previous years did not include hydroelectricity.

[6] Includes generation and purchases in Wisconsin. Data for Xcel prior to 2005 reflects fiscal years, ending in October.

[7]Calculated by MPSC Staff.

2.1 Biomass Energy Modeling Introduction

The general methodology used to model biomass resources for the Plan is to first estimate the potential biomass resources that could be made available in Michigan on a sustainable basis, then investigate likely technological applications for converting such resources into useful energy, including electric power, and then review the economics associated with those applications.

For purposes of this study, ethanol from corn and biodiesel from soy were not included among renewable resources for electricity production. Both biofuels are of increasing importance to Michigan as transportation fuels, but are not likely to be widely used in electric power production because they are generally higher in cost compared to solid biofuels and have greater value as vehicle fuel. Biodiesel, however, might be used in diesel generators, for emergency, standby service. Further, with the exception of an analysis of existing wood-fired boilers in the State of Michigan performed in conjunction with the analysis of CHP, there was no explicit analysis for the Plan of biomass used for thermal energy (such as wood, corn, or other materials used for space and water heating fuels).

In many ways, the assessment process for biomass resources is less certain compared to wind, hydroelectric, or solar resources. The basic reason is that biomass fuel handling, fuel processing, and energy conversion systems are not yet standardized to the same degree that they are for other generating options, so each application involves unique engineering design and that translates into a wider dispersion of cost estimates for biomass energy, even among systems that employ the same basic processes and component parts.[45] In addition, there is already a great deal of interest in a wide variety of bioproducts, including uses for food, fiber, chemical feedstocks, and fuels. Therefore, there may be significant competition for the use of Michigan biomass resources in the future, and only a portion of the sustainable yield might be available for energy production with only a fraction of that used to generate electricity. Thus, several conservatisms are included in the analysis of bioenergy potential for the Plan.

2.2 Cellulosic Biomass

Michigan already obtains about 1 percent of its electricity supply from power plants designed to burn primarily wood residues. Table 6 (p. 131) presents a list of Michigan's currently existing utility-scale wood-burning power plants, including their production data for 2005. In addition to the wood residues presently utilized for the production of electric power, recent data on wood and waste consumption in Michigan shows a total of nearly 60 trillion British Thermal Units (Btus) per year or approximately 3.85 million tons available.

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[45] A recently published report on a feasibility study for a biomass anaerobic digester system for west Michigan illustrates this point. In response to a request for preliminary proposals, which identifies a single type and quantity of waste to be converted into energy, the four firms propose four different kinds of methane digesters, and their preliminary costs range from approximately $3.7 to $12.5 million. These proposals do not include electric generating equipment, the estimates are only for the methane production systems. See *West Michigan Regional Anaerobic Digester Feasibility Study*, at http://www.michigan.gov/biomass.

Three major sources of additional cellulosic biomass resources were considered for modeling in the Plan.[46] They include: (1) surplus growth from commercial forest land; (2) biomass produced on abandoned cropland; (3) agricultural residues and plantings on conservation reserve program lands.[47] The following is a review of the major assumptions regarding each of these resource types.

2.2.1 Surplus Growth from Commercial Forest Land[48]

At present, only about one third of the annual sustainable forest growth in Michigan is being harvested each year to supply Michigan's forest products industries. The remaining two thirds either continues to accumulate in the forest or is lost to mortality. In theory, most of this surplus growth, estimated at 16.8 million dry tons per year, could be harvested for energy.

Practically speaking, however, there are many competing commercial uses for wood and wood residues, and it will be no small achievement to expand Michigan's commercial forest industry to take advantage of the significant quantities of wood residues modeled here. In fact, most of the biomass used today in Michigan's existing wood-burning power plants and biomass-fired boilers is wood residues from commercial forest harvesting and the primary forest products industries. Commercial forestry residues, including diseased wood, tree tops, branches, and stumps are typically chipped for delivery to wood-burning power plants. Primary forest products industry residues include bark, etc., from lumber production and a variety of wastes from pulp and paper making operations. Thus, to date there has always been a direct relationship between economic activity in Michigan's forest products industry and the residues that have traditionally been made available to wood-burning power plants.

Although harvesting this volume of wood residues would be a challenge for Michigan's existing forest products industry, Staff believes that the industry has sufficient supply elasticity to expand harvest volume over time. This may occur from an expansion of the industry or through new forest management programs. That expansion will take some time to accomplish, based on a review of recent changes in these industries in Michigan. If Michigan's forest products industries were to rebound from recent plant closures and expand, however, then the analysis

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[46] Data on these resources was provided by Dr. Raymond O. Miller, Manager of the Upper Peninsula Tree Improvement Center, Michigan State University. In addition, a task force working in conjunction with the Michigan Biomass Energy Program and Michigan Renewable Energy Program provided input for the analyses described here. Task-force participants included: Dulcey L. Simpkins, Ph.D. and Trista Gregorski, Michigan Biomass Energy Program; Greg Mulder, Coffman Electrical Equipment; Jessica Simons, Southeast Michigan Resource Conservation & Development Council; Anthony Weatherspoon, Michigan DNR, FMFM Division; Prof. Karen Potter-Witter, MSU Dept. of Forestry; Julie Baldwin and Tom Stanton, Michigan PSC Staff.

[47] Conservation reserve program (CRP) provides annual rental payments and cost-share assistance to establish long-term, resource conserving covers on eligible farmland. See http://www.fsa.usda.gov/FSA/webapp?area=home&subject=copr&topic=crp.

[48] In order to be designated by the U.S. Forest Service as commercial forest land, parcels must meet minimal productivity standards, in terms of the annual sustainable yield of timber, and must be available for forest management activities. Parcels that are restricted from harvesting or are otherwise sensitive sites are not included in the basic inventory of commercial forest land.

completed for the Plan suggests there would be plenty of biomass resources, on a sustainable basis, to fuel roughly a doubling of Michigan's existing wood-fueled power plants using only the residues from the expanded wood harvesting and primary forest products production.

Table 6: Michigan Utility Scale Wood-Burning Power Plants (2005 Production in MWh)

Wood - Burning Power Plants	Plant Capacity (MW)	2005 Generation (MWh)
Cadillac Renewable Energy	34.0	219,150
Genesee Power Station	35.0	233,503
Grayling Generation Station[1]	36.2	254,721
Hillman Power Company[1]	18.0	134,572
Viking-Lincoln[1]	18.0	144,360
Viking-McBain[1]	18.0	138,971
Total	**159.2**	**1,125,277**

[1]Licensed scrap-tire end user. (Feedstock may include scrap-tires.) Source: Consumers Energy Annual Report, 2005
See http://www.michigan.gov/documents/wood_energy_in_michigan--final1_169999_7.pdf, p. 16 for map of plant locations.

In the near-term, however, increased demand for waste wood material could cause the fuel price for existing wood-burning generating facilities to increase.

Another potential expansion, however, is through advanced forest management practices. That approach does appear promising, but would require substantial investments. In this approach, cullings from more aggressive forest management practices become the primary fuel for the near-doubling of Michigan's existing wood-fueled power plants. Again, the analysis completed for the Plan suggests there would be plenty of biomass resources, on a sustainable basis, to meet the needs modeled here.

Ultimately, these two different paths are not necessarily mutually exclusive. As long as either or both happen to a sufficient extent, there would be plenty of biomass resources, on a sustainable basis, to meet the needs modeled here. In addition, however, it must be understood that there are many competing and complementary uses, not only for forest products but also for forests themselves. Forests provide many vitally important natural services, including helping to prevent soil erosion, ensuring biodiversity, and creating habitat for wildlife. Forest lands are critically important to Michigan's travel and tourism industries. Policy makers must be vigilant to assure that poor forest management is not an unintended effect of energy policies intended to promote greater use of biomass energy resources. To the contrary, among all possible uses, the use of biomass for energy is generally considered preferable only to landfilling. Ideally, higher value purposes for biomass as a raw material for paper or lumber products, or as a chemical feedstock, will be maximized and only residues not suitable for such higher purposes will be converted to energy. Furthermore, it is imperative that some biomass residues should remain on the forest floor, in order to ensure continued productivity of forest soils and biodiversity.[49] Still, it is generally understood that conscientiously applied forest management practices can simultaneously improve forest productivity while helping to meet this entire variety of purposes.

2.2.2 Biomass Produced on Abandoned Cropland

Approximately 3.2 million acres of cropland has been abandoned in Michigan since 1950. It is assumed that 1.9 million acres is presently standing idle, which might make it available for growing energy crops such as willow, poplar, or switchgrass. Willow and poplar have a three year harvest cycle. Switchgrass requires three years to mature to the first harvest, and then it can be harvested annually. Based on those assumptions, presently abandoned cropland could potentially contribute an estimated 5.7 million dry tons to the annual energy needs of the state.

2.2.3 Agricultural Residues and Plantings on Conservation Reserve Program Lands

Active cropland is producing a range of commodities, some of which can be diverted into energy feedstocks. These crops are not included here since it is assumed that farming will continue regardless of the end product. The potential for additional production lies in the use of non-traditional sources like crop residues and perennial crops (like switchgrass) growing on Conservation Reserve and Wetland Reserve lands. Together these sources of biomass might yield about 5.0 million dry tons of biomass. Table 7 summarizes the data regarding cellulosic biomass resource estimates.

Table 7: Michigan Additional Cellulosic Biomass Resource Estimates

Resource Type	Resource Potential (dry tons/year)	Exclusions	Resource Available (dry tons/year)[1]
Surplus Growth from Commercial Forest Land	16,800,000	86%	2,352,000
Biomass Produced on Abandoned Cropland	5,700,000	86%	798,000
Agricultural Residues and Plantings on Conservation Reserve Program Lands	5,000,000	86%	700,000
Total			**3,850,000**

Notes: Resources are "additional" to those already in use at present. Data on these resources was provided by Dr. Raymond O. Miller, Manager of the Upper Peninsula Tree Improvement Center, Michigan State University.

[1]Refer to text for conversion from dry-tons/year to MW and MWh.

In practice, each MW of wood-fired electric power uses approximately 10,000 tons of wood residues per year. This assumes the power plant operates at approximately 80 percent capacity,

[49] Ash residues from wood combustion can often be reapplied to forest or agricultural lands as a soil amendment with positive results for productivity, as long as the ash does not contain high quantities of metals or potential pollutants.

generating about 7,000 MWh per year, per MW of capacity.[50] As evident from the above, Michigan is estimated to have an additional 27.5 million dry tons of biomass available that could, in theory, fuel 2,750 MW of generation each year. For modeling purposes, however, only14 percent of this cellulosic biomass potential (about 3.85 million dry tons per year) was assumed to be available for electricity generation by 2016, and a capacity factor of 80 percent was used for analyzing cellulosic biomass energy potential.[51] The large exclusion percentage is a conservative assumption intended to reflect competing land uses, high transportation costs for agricultural and forestry residues (which effectively limit the distance from resource lands to biomass generating facilities), and stiff global competition in the paper and forest products industries.

Existing biomass fueled facilities in Michigan, as depicted in Table 6, are predominantly wood-fired boilers. Future applications could include biomass conversion via direct combustion, gasification, or anaerobic digestion, and biomass could be used in stand alone electricity generators, in CHP applications, or via co-firing in coal-burning power plants. The resource analysis completed for the Plan does not assume any particular conversion approach or application technology, but costs associated with cellulosic biomass facilities are based on representative costs for direct combustion facilities like those listed in Table 6. It should be noted, however, that this modeling does not address biomass gasification. Preliminary research suggests a potential for roughly doubled conversion efficiency using gasification, which implies a much greater potential for cellulosic sources if gasification proves practical and economical.

2.3 Anaerobic Digestion

Anaerobic digestion converts organic wastes into methane, which can then be used to fuel an electric generator. The CNF report estimated that 51 MW of generating capacity was available in Michigan, assuming that farms with 500 or more head of cattle would provide the most likely sites for this option. For the Plan, Staff added swine and poultry operations and wastewater treatment facilities. These farms have the potential to contribute an additional 15 MW of generating capacity. It should be noted that the estimate of farm-based electricity production is based on the number of Michigan farms that are thought to be large enough to support economical anaerobic digesters. Additional generation, from facilities that aggregate wastes from many smaller operations, is not included. Staff is not yet convinced that this is an economically viable option, given the additional costs associated with transportation.[52] Another opportunity being explored for future anaerobic digester projects is blending animal wastes with food processing wastes. Mixing the two waste streams increases biogas production and thus electricity output. Locating digesters for easy access to multiple waste streams could also provide additional generation that might be used to meet RPS targets.

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[50] See http://efile.mpsc.cis.state.mi.us/efile/docs/14031/0161.pdf, p. 134.

[51] In comparison, the average capacity factor in 2005 for Michigan's major existing biomass fueled facilities, as shown in Table 6, was 81%.

[52] See *West Michigan Regional Anaerobic Digester Feasibility Study*, at http://www.michigan.gov/biomass.

Additional electric generation potential of approximately 30 MW was calculated based on an analysis of wastewater treatment plants with sufficient flow rates. While some wastewater treatment plants already have anaerobic digesters on site, the installation of electric generation equipment would still be necessary. For the Plan, it was assumed that 15 MW of the potential 30 MW would be reached by 2016.

The anaerobic digestion capacity factor was adjusted from 90 percent used in the CNF modeling to 80 percent for the Plan modeling. At the time the CNF report was written, very limited operational data was available for anaerobic digestion. However, data is beginning to become available as new projects are developed. Installations in Vermont's Cow Power™ program have experienced capacity factors averaging about 77 percent.[53] For Plan modeling purposes, Staff believe updating the capacity factor from 90 percent to 80 percent provides a closer estimate of what might be an achievable anaerobic digestion capacity factor. A new Michigan dairy farm anaerobic digester system began operating in November 2006 and a second project is expected to begin generating electricity in April 2007. More data will be known about anaerobic digestion capacity factor values as experience is gained from these projects.

2.4 Landfill Gas

Landfill gas likewise relies on the conversion of organic material to methane, which is used as a fuel for electric generation. Staff adopted the quantities and costs of landfill gas generation estimated to be available from the CNF.

2.5 Biomass Resources and Combined Heat and Power Analysis

Combined heat and power systems typically use energy sequentially to generate steam and then electricity, or electricity and then steam. The steam is used to provide industrial process heat or for building space or water heating. In some systems, called tri-generation, an absorption chilling circuit is added so that chilled water can be provided as a third potential energy use.[54] CHP systems can be a preferred method of energy conversion because they make greater use of the energy inherent in the fuel.

CHP is not new technology, by any means. Michigan has a long history of CHP facilities that provide process steam for industrial facilities, district heating systems in urban areas and for some of Michigan's largest college and university campuses.[55] Biomass-fueled CHP is also a tried and true technology in some Michigan installations. For example, Dow Chemical used a

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[53] Dunn, David J. (2006, May), *Financial Incentives for New Renewable Generation on Vermont Dairy Farms*. Presented at Renewable Portfolio Standards East Conference, Cambridge MA, for Central Vermont Public Service Corporation.

[54] CHP stands for combined heat and power. CHP plants incorporate both power and heat from a single heat source.

[55] District heating systems grew in the time period through the first half of the 20th Century. Later, as natural gas became more readily available and the price of natural gas remained low during roughly the 1970s through the 1990s, many district heating customers replaced their use of the steam from central power plants with cheaper natural gas. Though the natural gas price trend has reversed and prices have been volatile in the early years of the 21st Century, district heating systems have not yet recovered the sales lost.

22 MW facility for many years, fueled by wood waste, and Central Michigan University operates a 1 MW system that has successfully provided electricity and steam for its campus, on and off since 1985.

There are some industrial boilers that are presently fueled with wood residues. Those wood fueled boilers were not included in the CHP analysis undertaken by the Alternative Technologies Workgroup. Instead, they are considered to be available in the Renewable Energy report to be converted to biomass-fired cogeneration systems, utilizing a small portion of the available cellulosic biomass resources. With the intent to avoid double-counting these facilities in both CHP and biomass assessments, their potential contribution is embedded in the biomass electricity production estimates, above. In essence, the biomass resources identified in the Plan are thought to be available for utilization in a variety of facilities, and it is expected that perhaps sites with existing wood-fired boilers would be among the first to consider adding electric generation to become biomass-fueled CHP facilities. If those facilities were to add electric generation, it is estimated that their total biomass fuel use would increase by approximately one-third; approximately 45,000 dry tons per year or roughly 1 percent of the total available cellulosic biomass resource.

The analysis of biofuel availability for Michigan shows a substantial potential. Almost any of those materials can be utilized in CHP facilities, depending on the energy conversion technologies applied. Anaerobic digesters, landfill gas facilities, and wastewater treatment plants can all utilize methane fuel in a CHP boiler system or gas turbine generator (either simple-cycle or combined cycle). Solid biomass can be converted to liquid or gas fuels prior to combustion using biochemical or thermal processes, or the solid fuels can be utilized directly in solid-fuel combustion boilers. In fact, solid biomass can be blended in coal-fired boilers, in a process called co-firing. Co-firing involves the simultaneous combustion of different fuels in the same boiler.[56] CHP systems can be developed using any of these basic types of energy conversion technologies.

2.6 Biomass Resources Summary and Conclusion

In many ways, utilization of the biomass potential identified for modeling in the Plan ultimately depends a lot on public policies, which are discussed later in this report. If policies are established which remove barriers and support utilization of biofuels for electricity production, then the state could expect to successfully meet the potential for biomass energy modeled in the Plan. With or without such policy changes, however, making available the quantity of new biomass electric power generation modeled for the Plan will represent substantial technical challenges. This Plan cellulosic biomass resource assessment reflects a near doubling of Michigan's existing biomass fueled electricity generation, at a time when Michigan forest products industries have been contracting rather than expanding. With favorable policies, however, Staff is confident that the quantities of biomass resources identified here, and perhaps even substantially more, could economically be obtained and converted to electricity.

[56] Simpkins, Dulcey, (2006, June), *Clean Energy from Wood Residues in Michigan*, p. 35. Available online at http://www.michigan.gov/documents/wood_energy_in_michigan--final1_169999_7.pdf.

2.7 Wind Energy Modeling for the Plan

Wind energy potential for the Plan was analyzed based on a few basic incremental changes applied to data used for the Capacity Need Forum report. Similar to the analysis of biomass energy resources, a very large gap currently exists between the technical potential and achievable near-term potential for wind generated electricity in Michigan, based on the best available wind energy mapping completed for the state.

The CNF estimate of potential wind generation began with wind mapping completed for Michigan in 2004.[57] The wind assessment was co-sponsored by the Michigan Energy Office and the U.S. Department of Energy's National Renewable Energy Laboratory and provided wind speed and wind power density maps for Michigan which were verified at 50 meters above the ground. These maps served as the basis for estimating the technical potential for wind generation in Michigan.

The CNF estimate of wind generation was calculated for those regions within Michigan with an on-shore wind class of 4 or higher (also designated 4+) at a 50 meter height. Class 3 regions make up a large part of the Lower Peninsula at 50 meter heights but were deemed to have insufficient wind speed and duration to be economically harnessed. Therefore, the CNF participants excluded the class 3 regions from their analysis of available wind energy in Michigan. Additional downward adjustments to wind potential in the state were made by CNF participants to account for the difficulty of building facilities in designated wilderness areas, state and national forests, urban areas, wetlands, and other areas. After the exclusions, 831 MW of electric generating capacity was estimated to be available from on-shore sites with class 4+ wind regimes. This amount was further reduced by 50 percent as another conservative adjustment to account for potential local siting impediments.

Wind maps were also produced for 70 meter and 100 meter heights, where wind speed and duration are typically greater than at lower elevations. Modern utility scale wind generators are typically installed with hub-heights of 70 to 80 meters, however, and the data currently available for 70 and 100 meters must be considered preliminary and not yet verified. In 2005 and 2006, several wind developers requested utility interconnections in Michigan, and information based on those requests led Michigan Public Service Commission Staff and other interested parties to question the accuracy of information provided in the 2004 Michigan wind maps. The crux of the questions revolved around the fact that previous National Renewable Energy Laboratory (NREL) estimates of wind potential in the Thumb area of Michigan were far lower than requests already published in the Midwest Independent System Operator (MISO) queue by early 2006 (see Table 8, p. 140).

As NREL researchers explain, the potential wind energy presented in the 2004 maps for Michigan must be considered to be a general estimate. The existing wind maps for Michigan are

[57] See http://www.michigan.gov/cis/0,1607,7-154-25676_25774-101765--,00.html.

intended to provide a general picture of wind availability, but those maps must be supplemented by on-site wind data measurement and analysis prior to siting wind generators.[58]

At sites that have been measured in the Midwest, substantial wind shear has been identified at heights above 50 meters. That implies that wind speed and power could be substantially greater at typical hub-heights (70 to 80 meters) for currently installed utility-scale wind generators, compared to what has been predicted at 50 meters. For example, in northwest Indiana near Lake Michigan, tall-tower measurements have indicated more wind shear and a greater wind resource at 90 meters than would be estimated by conventional assumptions and wind energy rules of thumb based on upward extrapolation of the 50 meter data at the same location.[59] This example points out how the map estimates (largely based on data from weather stations, collected at 10 meters) and even measurements taken at 50 meters can be misleading when it comes to estimating the resource available for potential wind development for large wind turbines with hub-heights of 70 meters and higher.

As shown in Table 8, Michigan wind energy projects totaling 1,191 MW have contacted MISO at some point in the past couple of years, requesting grid interconnection. During the time period covered by research for the Plan, however, there were significant developments regarding the MISO queue in the Thumb area of Michigan. In total, 911 MW of wind generation in Michigan's Thumb had requested interconnection studies from MISO. Costs associated with interconnections at both the distribution and transmission levels have resulted in many of the proposed projects withdrawing from the MISO queue. Presently, out of the initial 911 MW, only about 400 MW remain in the queue and interconnection facilities studies for these projects are ongoing.[60] The amount of future wind development in Michigan may be constrained by the limitations of the existing transmission/distribution infrastructure and the costs necessary for upgrading it to accept large quantities of wind generation.

The CNF based its estimates for Michigan's wind energy potential on wind maps provided by NREL. These maps generally depict wind regimes in the state, but must be supplemented by local wind studies. Based on proposed projects in the MISO queue (Table 8) and discussions with wind energy participants in Michigan, Staff initially increased the amount of wind estimated

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[58] These cautions about appropriate uses for the Michigan wind maps were included in a draft report, *Michigan Wind Energy Potential, 2006-2020*, which was provided to participants in the Capacity Need Forum project. See http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/othergen/mi_wind_energy_potentialjun14_2005.pdf. In particular, see footnote 7 on p. 2, and the discussion about exclusions, on p. 6-7.

[59] The measured wind resource at 50 meters for this Indiana location reflected low class 3 wind power and an average 6.7 meters per second wind speed. At 90 meters, however, it measured 7.7 meters per second, which would be equivalent to almost class 5 at 50 meters. The gross capacity factor at 90 meters was 42.6 percent for the GE 1.5 MW 77-meter hub height machine (personal communication from Dennis Elliott, National Renewable Energy Laboratory, August 4, 2006).

[60] Because some of the wind generators previously included in a MISO group study for interconnections requested in Michigan's Thumb area recently withdrew from the queue, a new facilities study must now be completed to reflect the lower number of MW under consideration for interconnection in this area. The new facilities study is expected to be completed by October 2006. When completed, it will be posted on the MISO website, under *MISO Generator Interconnection Queue*, at http://www.midwestiso.org/page/Generator+Interconnection.

to be available for the Plan to 525 MW. In reviewing wind energy resource information for Michigan, there is a technical potential for much more than the 525 MW of installed capacity modeled for this report. The initial modeling for the Plan begins with an estimate of wind energy potential for the coming several years, based on the projects already participating in the MISO queue that appear on track to be developed. There is ample reason to believe that additional wind energy resource development will prove easier as time goes by and more experience is gained with the early installations in Michigan. This has certainly been the pattern in many other states in the U.S.[61]

Table 9 (p. 140) shows the comparison of the wind power projections for the Plan and the Capacity Need Forum. Several Plan participants, notably the Energy Office, have indicated that the conservative adjustments made to the NREL study result in Michigan's wind energy potential being significantly underestimated. Specifically, they note that a wind class encompasses a range of wind speeds. For example, class 3 runs from an average speed of 6.4 meters per second to 7.0 meters per second. Even average speed differences of 0.5 meters per second can make a large difference in the ability of a site to produce electricity economically. According to some of the commenters, better class 3 sites may be suitable and capable of producing electricity economically, especially when one considers that the wind speeds are measured from a 50 meter height. Commenters note that some of the class 3 wind regions measured at 50 meters are likely to be class 4+ at 70 meters or 100 meters; the heights at which commercial wind turbines are more likely to be built. Commenters also indicate that the proposed schedule for achieving renewable generation is unnecessarily protracted. Some commenters pointed out that no substantial impediments were identified by Renewable Energy Workgroup participants to a somewhat accelerated implementation of portfolio standards.

NREL has estimated that approximately 15,700 MW of potential wind generation is available from on-shore class 3 wind regions within Michigan based on 50 meter measurements. Many of these sites are more favorable than others and are likely to have class 4+ wind characteristics at 70 to 100 meter hub heights. Based upon the observations, information, and recommendations received from participants, Staff reassessed Michigan's achievable wind energy potential based upon slightly less conservative assumptions of wind availability. Considering the role played by wind shear at higher elevations and the NREL wind maps for 70 and 100 meters, Michigan has substantially more wind generating capability than the conservative assumptions initially adopted for the Plan. If one assumes that a quarter of the class 3 wind regions can be economically harnessed at 70–100 meters, that would still produce nearly 4,000 MW of wind capacity. If one were again to assume that only half this amount could be harnessed because of siting difficulties (in addition to the exclusions already made in arriving at the 15,700 MW amount), that would leave nearly 2,000 MW of potential capacity available from class 3 regions. This 2,000 MW amount together with the 415 MW from the class 4+ regions used in the CNF serves as an upper estimate of the wind potential of 2,415 MW that can be harnessed in Michigan by the end of 2015 to meet a renewable energy portfolio target. Furthermore, information provided to the Staff indicates that ample high-quality sites are available, in areas thought to be sufficiently accessible to wind developers, to move the target compliance date to 2015.

[61] Please see the discussion in the Policy document, Appendix Volume I, for additional insights about how policy changes are expected to open the market for wind energy development in Michigan.

When this amount of wind energy is added to other sources of renewable energy, the result is a little more than 10 percent of Michigan's forecast energy sales by the end of 2015. The broader assessment of 10 percent combined with the initial more conservative estimate of 7 percent produces a range of reasonable portfolio targets running from seven to 10 percent. A renewable portfolio target within this range should be achievable on reasonable terms by the end of 2015.

It should be noted that achieving the upper end of this range may require significant additional transmission investment. Staff anticipates working with MISO and Michigan's transmission owners to assure that sufficient transmission will be available when needed. Staff will also work with Michigan distribution utilities to assure the Michigan system will be able to accommodate the major use of wind power anticipated by this proposal.

Table 8: Michigan Renewable Resource Facilities in MISO Interconnection Queue, Including Withdrawn Projects (September 2006)

MISO Queue Number	County	In Service Date	Max Summer Output (MW)	Fuel Type	Point of Inter-connection
~~37494-01~~	~~Shiawassee~~	~~01-Jan-03~~	4	~~Biomass~~	
38377-01	Sanilac/ Huron	01-Nov-06	36	Wind	DTE 41kV system near Talbot to Delaware/Neff/Sandusky ckts
38394-02	Huron	30-Oct-07	37.5	Wind	
38425-02	Huron	30-Oct-06	158	Wind	
~~38425-03~~	~~Sanilac~~	~~30-Oct-07~~	~~158~~	~~Wind~~	~~ITC 120kV circuit from Sandusky to Lee~~
38457-02	Oceana	01-Oct-06	100	Wind	White Lake Substation
38478-01	Sanilac	30-Oct-07	40	Wind	ITC 120kV Sandusky Station
38484-04	Huron	30-Oct-07	50	Wind	DTE 41kV system north of Bingham Station
38485-01	Huron	30-Oct-07	100	Wind	DTE 41kV Pigeon Station
38509-01	Huron	15-Oct-06	60	Wind	120kV Bad Axe-Arrowhead line DTE
38660-01	Huron	01-Aug-07	60	Wind	Existing 120kV line near Rapson Rd and Minden Rd
38663-01	Missaukee	01-Aug-07	60	Wind	69kV line near La Chance and Steif Roads
38715-02	Ontonagon	10-Jun-08	14	Biomass	White Pine Sub
~~38835-02~~	~~Huron~~	~~30-Oct-07~~	~~37.5~~	~~Wind~~	
~~38835-03~~	~~Huron~~	~~30-Oct-07~~	~~37.5~~	~~Wind~~	
~~38835-04~~	~~Huron~~	~~30-Oct-07~~	~~37.5~~	~~Wind~~	
38888-01	Allegan	01-Jul-08	102	Wind	Argenta to Tallmadge 345kV line
38937-01	Huron	15-Nov-07	49.5	Wind	ITC Wyatt-Sandusky 120kV
38937-02	Sanilac	15-Nov-07	49.5	Wind	ITC Wyatt-Sandusky 120kV
Total MW **(Includes MW from withdrawn projects.)**			**1,191**		
Total MW **(Does not include MW from withdrawn projects.)**			**920.5**		

Note: Strikeouts represent projects withdrawn from the MISO queue.
Above information is online at http://www.midwestiso.org/page/Generator+Interconnection.

Table 9: Wind Power Capacity Projections by Region for CNF and Plan

Region	MW Nameplate Capacity			Capacity Factor		GWh/Year		
	Plan 7% RPS Modeled (2016)	Plan 10% Accelerated RPS (2015)	CNF (2015)[1]	Plan[2]	CNF	Plan 7% RPS Modeled (2016)	Plan 10% Accelerated RPS (2015)	CNF (2015)[1]
Southeast Michigan	250	1,150	53	28%	25%	613	2,821	116
Balance of Lower Peninsula	200	650	285	28%	25%	491	1,594	624
Upper Peninsula	75	350	105	28%	25%	184	859	230
Total	**525**	**2,150**	**443**			**1,288**	**5,274**	**970**

[1] During the CNF modeling process, wind contributions were scaled up to the numbers shown to meet the required additions of the modeled portfolio standard (3 percent in 2008, 5 percent in 2010, and 7 percent in 2015).

[2] The wind capacity factor used was 20%, for both the 7% RPS modeled for the Plan and the 10% accelerated RPS.

The chief factors driving the cost of wind generation include the installed cost for the wind generator, interconnection costs and the expected capacity factor. Costs calculated on a kWh basis are highly dependent on the unit's capacity factor (on how often it operates, and at what percentage of its design capacity). For the CNF, Staff estimated the average capacity factor of wind generators at 25 percent. However, it seems reasonable to assume that wind developers are already targeting projects to sites with good wind resource characteristics, including high average wind speeds and capacity factors, and low interconnection costs. Prospective developers have indicated Michigan has considerable land area with estimated capacity factors of 30 percent or greater. Based on these assumptions and observations, Staff believe the 28 percent capacity factor used in modeling wind energy for the Plan is reasonably conservative.[62] A number of participants indicate there is a very large potential for wind energy generation off-shore, in the Great Lakes. Staff did not estimate, nor incorporate into the estimates, any off-shore wind generation.[63] This decision is based in large part on the assumption that anything more than experimental or pilot scale off-shore wind energy development is not likely in the next decade. Should off-shore wind development in the Great Lakes prove practical, however, current estimates show it could produce substantial additional energy for the Michigan system.

[62] Additional details explaining further the assumptions used in wind energy modeling for the Plan will be made available in a separate publication, to be posted on the Renewable Energy Workgroup website, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/renewables/renewables.htm.

[63] Background information about Michigan's offshore wind energy resources in the Great Lakes is available in a report completed for the Capacity Need Forum. See *Potential for MI Offshore Wind Energy* at http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/othergen/other.htm. As that report concludes, however, any development of offshore wind energy resources in Michigan waters of the Great Lakes is not likely to proceed until research is completed on many significant technical and policy issues. Thus, offshore wind is not likely to make any substantial contribution within the roughly 10-year time frame explored in modeling for the Plan. However, a 710 MW offshore wind farm is presently being considered for installation in Canadian waters in Lake Ontario. See http://www.renewableenergyaccess.com/rea/news/story?id=45079.

Some other participants question whether the cost assumed for wind generators is high enough to reflect current and future market prices. Instead of $1,425 per kW installed cost, some participants report current prices in the range up to $1,700. Staff recognizes that current prices may be significantly higher than the $1,425 incorporated into the model, but Staff notes the long-term general trend for wind energy costs has been declining relative to fossil fuel prices. Staff believes there are other important countervailing factors, too, that support the lower cost used in this modeling; even if the prices used do turn out to be inaccurate in the present and near future. First, prices for fossil fuel units are just as likely as wind machines to be affected by high commodity prices (for steel, concrete, copper, etc.), in which case the costs of both types of facilities will generally rise together and the relative cost comparisons will remain fairly stable. Second, wind conversion efficiencies are expected to continue to improve, and thus result in some combination of higher production and lower cost, but those improvements are not captured in this modeling. And, third, the current wind generator prices are partly a response to what are generally high short-term demands chasing limited manufacturing capability. The demand is caused in part by growth in many states' RPS targets combined with the on-again, off-again threat that federal production tax incentives will expire.[64] Thus, on the whole, Staff expects the current market prices for wind systems to moderate as additional manufacturing capability comes online and production increases to meet growing demand.

3. Renewable Energy Modeling Summary and Conclusions

The Plan's renewable resource assessment shows a potential for Michigan's electric supply portfolio to incorporate the renewable range running from about 7 percent to 10 percent renewable energy by the end of 2015. The conservative portfolio option, used for expansion plan modeling for the Plan, begins with the current level of approximately 3 percent renewable energy in the current supply portfolio and adds renewable energy totaling 4 percent of retail sales, to reach a statewide target of 7 percent. Based on the energy forecast for the Plan, this amounts to 1,123 MW or 5,590 gigawatt hours (GWh) of additional renewable energy by 2016 for the conservative case. Alternatively, the accelerated schedule depicted in Figure 3 begins with the current 3 percent level and increases to 10 percent by the end of 2015. Again, based on the energy forecast for the Plan, this amounts to 2,691 MW or 9,178 GWh. The resource assessment conducted for the Plan demonstrates that Michigan does have ample renewable resources available for statewide electricity production to achieve, in this timeframe and with little if any incremental cost, at least these levels of renewable energy production.

Figure 2 shows the renewable energy supply portfolio modeled. The accelerated renewable energy supply portfolio is shown in Figure 3. The specific divisions shown among the various sources of renewable energy depicted in both Figures should be understood to be illustrative only. As was discussed earlier in this report, the specific resources to be developed might include at least some contributions from solar and hydroelectric resources that have not been explicitly included in Plan modeling, and the resource potential investigated for both wind and

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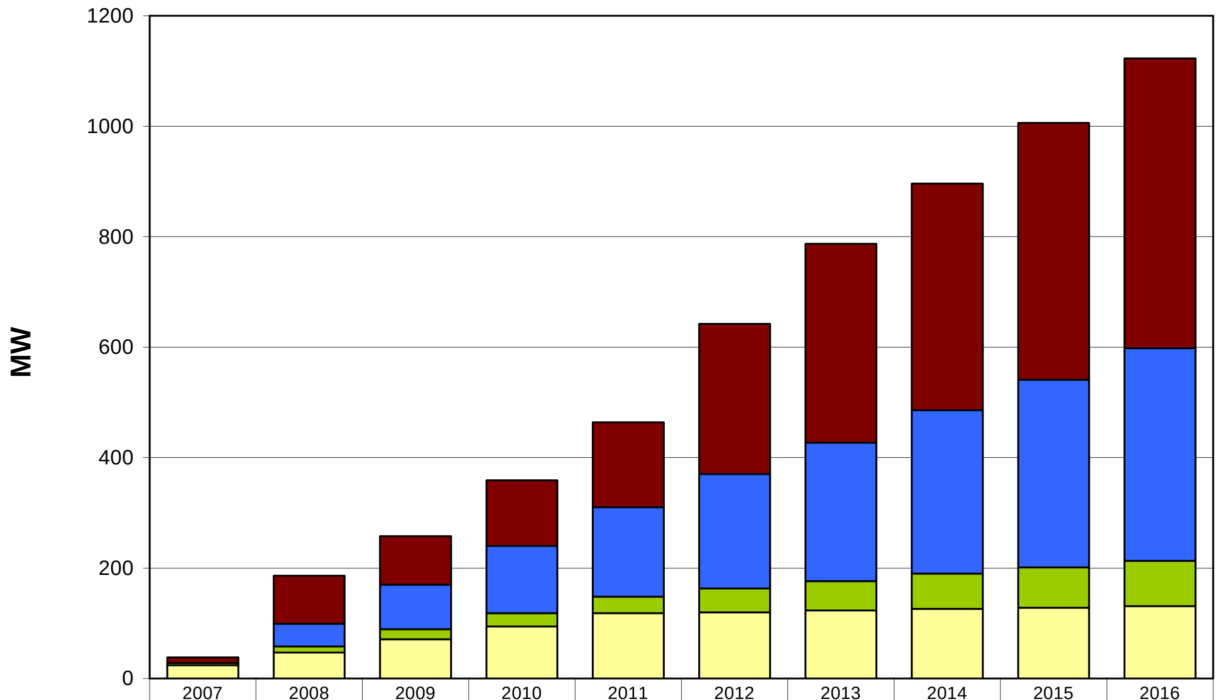
[64] The U.S. Congress passed on December 11, 2006, an extension of the wind energy production tax credit through 2008. See http://www.awea.org/newsroom/releases/Congress_extends_PTC_121106.html.

biomass is ample for either or both of those resources to exceed the quantities of production modeled here. Thus, the eventual contributions from each resource type might differ from the quantities depicted in Figures 2 and 3, but Staff is confident that these overall levels of additional renewable resources for Michigan's electric power production portfolio are achievable.

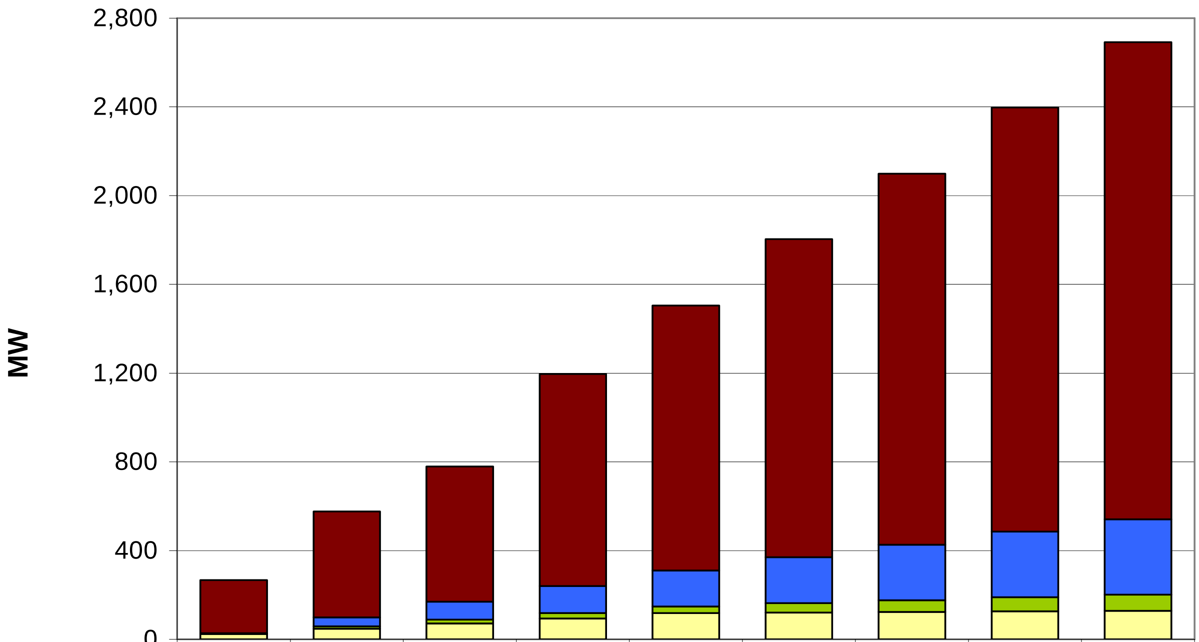
Figure 2: New Renewable Resources in the 7 Percent Portfolio (MW)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Wind	10	87	88	119	154	272	360	410	465	525
Cellulosic Biomass	0	41	81	122	162	207	251	296	340	385
Anaerobic Digestion	4	11	18	24	30	43	53	64	73	82
Landfill Gas	24	47	71	94	118	120	123	126	128	131

Still, reaching Michigan's renewable potential will require a substantial increase from the existing renewable resource base in Michigan, and reaching these levels within the expected timeframe will necessitate overcoming regulatory, technical, financial, and policy challenges. Nevertheless, as the modeling of various scenarios for the Plan demonstrates, the challenges associated with the addition of traditional energy resources or with reliance on neighboring markets for Michigan's future electric power supply are also perhaps equally or even more challenging. Therefore, Staff consider these preliminary targets, in the range from 7 to 10 percent renewable resources, to be reasonable for near-term policy consideration.

Figure 3: New Renewable Resources in the 10 Percent Accelerated Portfolio (MW)



	2007	2008	2009	2010	2011	2012	2013	2014	2015
Wind	239	478	609	956	1,194	1,433	1,672	1,911	2,150
Cellulosic Biomass	0	41	81	122	162	207	251	296	340
Anaerobic Digestion	4	11	18	24	30	43	53	64	73
Landfill Gas	24	47	71	94	118	120	123	126	128

CHAPTER 5

Alternative Technologies Workgroup Resource Assessment

1. Introduction, Overview, Methodology and Approach

1.1 Introduction

Governor Granholm's Executive Directive charged the 21st Century Energy Plan (Plan) participants to address "The appropriate use and application of energy efficiency, [and] alternative energy technology. . . ." It also directed participants to identify "[n]ew technology options to generate, transmit, and distribute energy more cleanly or more efficiently. . . ." To fulfill this directive, the Alternative Technology Workgroup identified new and enhanced electric generation, transmission, and distribution technologies that have recently become available or are likely to be available, in the not-too-distant future, to help meet the State's electric energy needs.

For purposes of this Plan, only combined heat and power (CHP) potential estimates were directly used in the modeling. Other forms of distributed generation can be assumed to be captured as part of the renewables modeling (reciprocating engines and perhaps Stirling engines), while the remainder (fuel cells and battery storage) are considered more niche applications that are either not sufficiently developed or have not yet made a significant contribution towards meeting Michigan energy needs.

The Workgroup investigated alternative technologies in two broad categories. The first category represents generation options that are not traditional central station plants and are collectively referred to as distributed energy resources (DER) or distributed generation (DG).[66] DG technologies allow production units to be located at or near the point of end-use, frequently on a customer's premises. CHP represents one type of DG application. The assumptions used for estimating the CHP potential for the expansion modeling program, are discussed in more detail in Chapter 5A of Appendix Volume II, which is the Estimate of Combined Heat and Power Potential document. The review of CHP and other DG applications is presented in Section 2 of this Chapter. The matrix that summarizes the technology characteapplications is presented in Chapter 5B, which is the Distributed Generation and Related Technologies Matrix document.

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[66] Generally speaking, DER can include any combination of demand side, distribution grid, and supply-side resources, whereas the term DG applies only to supply-side resources. Demand side resources affect the efficiency and time of use of services that utilize energy, almost always on the customer's side of the utility meter. Distribution grid resources affect the efficiency of energy delivery from generator to user, or enable monitoring, communications, and controls necessary for the implementation of other demand- or supply-side technologies. Supply-side resources involve the generation of energy. (See, for example, Lovins, A.B., Kyle Datta, Thomas Feiler, Karl R. Rábago, Joel N. Swisher, André Lehmann, and Ken Wicker; 2002; *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*; Snowmass, CO: Rocky Mountain Institute; www.smallisprofitable.org, p. 7; and U.S. EPA Glossary, *What is Green Power*, at http://www.epa.gov/greenpower/whatis/glossary.htm.)

The second group of technologies represents options for the modernization of the nation's electric transmission and distribution grid, including related sensing, monitoring, communications and control functions. These options are intended to make the electric grid more reliable, secure, and efficient. They will also facilitate the incorporation of DER installations, while maintaining system reliability. These are termed "Smart Power Grid" technologies, and they are briefly reviewed in Section 3 of this Chapter and in more detail in Chapter 5C of Appendix Volume II, which is the Smart Power Grid and Related Technologies document.

1.2 Overview

The changing nature of the country's electric industry – initiated by passage of the federal Public Utilities Regulatory Policy Act of 1978 (PURPA),[67] supplemented and expanded through passage of the federal Energy Policy Acts of 1992 and 2005 (EPACT'92[68] and EPACT'05[69]), and other federal and state initiatives including Michigan's 2000 PA 141[70] – helped to create and support growing interest in distributed energy resources. Some of the expected benefits from the application of DER technologies include:

1. flexibility for customers to choose the best energy system for their individual circumstances;
2. reliable power, especially in areas where outages are common;
3. high-quality, premium power for sensitive applications;
4. improved power quality, including voltage stabilization for circuits that might otherwise be under greater stress during periods of peak or near-peak utilization;
5. efficiency improvements when DER options are used, often incorporating combined heat and power equipment for space, water, or industrial process heating, cooling, and related applications;
6. utility system cost and customer bill savings, often resulting from reduced customer peak demand and demand charges;
7. power provided less expensively to remote applications like cellular communications towers;
8. environmental benefits associated with emissions reductions, frequently through renewable energy technology applications; and
9. additional fuel source diversity, frequently through renewable resources such as biomass, solar, and wind.

[67]For more information on the Public Utilities Regulatory Policy Act of 1978 (PURPA), see link for article *Electricity Restructuring Background: The Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992*, http://www.ncseonline.org/NLE/CRSreports/energy/eng-36.cfm.

[68]Link to Energy Policy Act of 1992: http://thomas.loc.gov/cgi-bin/bdquery/z?d102:HR00776:@@@D&summ2=m&.

[69]Link to Energy Policy Act of 2005: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ058.109.

[70]Link to 2000 PA 141 (MCL 460.10 et seq.): http://legislature.mi.gov/doc.aspx?mcl-460-10.

Since energy planning is a dynamic process and energy markets are changing rapidly, it is important for planners to be aware of alternative technologies and the likely roles they might play in meeting the state's energy needs. From a design and engineering standpoint, it is important that steps taken in the near future make it easier, not harder, to implement promising technologies when they become available. It is likewise important to consider these technologies when assessing policy needs to assure that policy recommendations will not inadvertently preclude adoption of new technologies or impose unintended consequences that might undermine the benefits they could otherwise confer.

Due to the large number and widely varying types of alternative technologies related to distributed generation, advanced energy storage systems, and advanced distribution and transmission technologies, the process of analyzing these technologies was divided into four teams: (1) Alternative Technologies; (2) Combined Heat and Power; (3) Smart Power Grid; and (4) Policy (comprised of participants from both the Renewable Energy and Alternative Technologies Workgroups).

The goals of the Alternative Technologies Workgroup were to identify and characterize alternative technologies related to distributed generation, transmission, and advanced storage, focusing on reliability, safety, security, efficiency and compatibility with any given system. The Workgroup also sought to identify barriers to adoption and implementation, and related interconnection issues.

The goals of the Combined Heat and Power Team were to explore the sites identified in the Capacity Need Forum (CNF) report to the extent possible to validate, refine and extend the potential capacity available in Michigan from combined heat and power projects. The Team also identified barriers to, and developed recommendations for, the implementation of such projects in Michigan.

The goals for the Smart Power Grid Team were to identify and summarize current and national programs that are involved in the process of organizing, studying, specifying, designing, testing and implementing the hardware and concepts of a Smart Power Grid, and also, to provide additional information on technology options, barriers to adoption, commercial readiness, and applications related to smart power grid architecture and communications.

1.3 Methodology and Approach

The overall process utilized in developing this report involved a number of stakeholders from various fields and backgrounds. Experts in electric generation, distribution and transmission, advanced storage, and regulatory and policy matters provided input in developing the materials presented as part of the Plan for the state of Michigan. Wherever possible, the participants strived to reach consensus on the methodology and approach used in gathering and cataloging the data and subsequent findings contained in this document. If the stakeholders involved were unable to reach consensus on particular issues, Michigan Public Service Commission (MPSC or Commission) Staff employed its best judgment and a consultative process open to all participants, to ensure, to the extent possible, the quality and accuracy of the data in this report.

Due to the inherent uncertainties associated with the evaluation of alternative technologies for generation, distribution and advanced energy storage, the various technologies evaluated as part of this report were those considered by participants to be the most likely to be commercially available and practical for application in the near to mid-term planning horizon. Workgroup participants acknowledge that as advancements to the various technologies occur over time, the commercial viability and economic affordability of these options will likely change as well.

To the extent that some of these technologies have already been deployed in Michigan, their influence on historical demand and energy use is expected to be captured, at least in part, by the methods used to establish the forecast of future electric power and energy needs. For example, solar electric generating technologies are already commercially available, even though they are still relatively more expensive compared to current and expected near-term electric power rates. To the extent that a small number of customers are already incorporating solar electricity into their homes or commercial buildings, however, the historical trend would be expected to be reflected in Michigan electric utility forecasts.

Unlike central station power, there is relatively little cost and operating history available in the public domain regarding many alternative generation technologies, including some of those technologies that the Workgroup identified as promising. The Workgroup participants' best estimates of the cost, performance and availability of these technologies are summarized in the three documents: Chapter 5A: Combined Heat and Power; Chapter 5B: Distributed Generation and Related Technologies Matrix; and Chapter 5C: Smart Power Grid and Related Technologies.

2. Distributed Generation Resource Assessment

Distributed Generation resources can include both stand-alone resources and those intended to operate in parallel with the utility distribution system.[71] DG can be beneficial to both the electricity consumers served by the DG and to the utility system as a whole, if the systems are properly engineered and the power output is carefully integrated into the grid. Workgroup participants generally acknowledge and accept that centralized electric power plants will remain the major source of base-load power supply for the foreseeable future. However, DG can complement central station power plants by providing incremental capacity to the utility grid or to an end user, providing back-up power in emergencies, and providing more personalized energy options to meet customer needs. Installing DG at or near the end user can also, in some cases, benefit the electric utility by allowing the reduction, postponement, or avoidance of otherwise required transmission and distribution system upgrades. For the consumer, the potential lower cost, higher service reliability, high power quality, increased energy efficiency, and energy independence are all reasons for continued interest in DG.

[71] Any electrical connection/interconnection between a given utility distribution system and a DG generation source, usually governed by an inverter, which controls, protects and filters direct current (DC) input to alternating current (AC) output power such that parallel operation can occur.

The following DG technologies were evaluated by the Alternative Technologies Workgroup:

1. combined heat and power; fuel cells;
2. reciprocating engines;
3. Stirling engines; and
4. micro-turbines and small-scale combustion turbines.

In addition to these DG technologies, advanced energy storage and battery systems were also investigated by Workgroup participants.

2.1 Combined Heat and Power

Combined heat and power technology often takes process steam generated by industrial or large commercial boilers and passes the steam through a turbine generator before it is used for its ultimate purpose. In some applications natural gas fires a combustion turbine or reciprocating engine and the waste heat in the exhaust or cooling water is used to make steam, hot water, or direct heat for process use at the site.[72] CHP technology offers increased fuel efficiency compared to traditional, central station power generation units.[73] The scale of these installations can range from a fraction of a megawatt per unit to installations comprising multiple units of over 1,000 megawatts (MW).[74]

CHP is practically synonymous with the term, cogeneration. These are installations in which waste heat (almost always in the form of steam or hot water) is captured and used to heat buildings and/or drive turbines in order to produce electricity on-site. (Other uses include absorption chillers and to provide hot water for cleaning.) There is significant CHP technical potential in Michigan, due to the large existing base of manufacturing and industrial facilities. This potential was explored in depth by the CHP Team as part of the Plan development process.

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[72] For more information about CHP, see the U.S. Combined Heat and Power Association website, http://uschpa.admgt.com/index.html.

[73] The conversion of fuel energy to useful work in a typical central-station electric generator is typically on the order of 30-40 percent efficient, and then from 5-15 percent of that electricity can be lost in transmission and distribution, so that the total efficiency of conversion from fuel to customer's electric outlet is frequently between 25-33 percent. That is, for each one unit of energy delivered to the customer in the form of electricity, about three to four units of fuel energy are used. CHP systems increase efficiency very substantially by converting fuel energy to two or more forms of useful energy, typically making electricity and using as much of the residual thermal energy as practical for some on-site purposes. By locating CHP units as close as practical to both electric and thermal loads, less energy is lost in transmission and distribution, too. Total system efficiencies for CHP applications can often be roughly twice that of central station power plants. See websites of the U.S. Combined Heat & Power Association, http://www.uschpa.org and Midwest CHP Applications Center http://www.chpcentermw.org/home.html.

[74] In practice, most CHP systems are relatively small in scale (less than 100 MW). There is no technical reason why CHP systems cannot be much larger, as is evidenced by the MCV cogeneration plant in Midland (over 1,200 MW). However, there are few opportunities to use the very large quantities of heat energy associated with central station power plants, so in the past it has been unusual for CHP systems to be built at scales larger than about 100 MW.

The Alternative Technologies CHP Team obtained the most recent boiler data available from the Michigan Department of Environmental Quality, Michigan Air Emission Reporting System (MAERS) in order to improve the accuracy of estimates of the statewide CHP potential. The MAERS data (2005 reporting year) used as part of this process provided a more detailed measurement of CHP potential based on actual fuel consumed annually at Michigan boiler facilities, as reported in the MAERS data. The resulting analysis indicated approximately 720 MW of power could be produced by the various existing systems that have favorable characteristics for CHP installations. This potential CHP capacity, by sector, is depicted in Table 1.[75]

Table 1: Michigan Estimated CHP Potential

Sector	Percent of Total	Total CHP Potential (MW) [1]
Automotive/Transportation	43%	310
Mining/Metal Forming	18%	130
Pulp/Paper	15%	108
Chemical/Pharmaceutical	10%	72
Food Processing	9%	64
Other	5%	36
Total	100%	720

Source: MDE Quality, Michigan Air Emission Reporting System (MAERS) boiler data available from the 2005 reporting year.

[1] The potentials indicated here, in MW, represent 100 percent of the total potential identified by the CHP team. Due to existing economic factors related to fuel and technology costs for CHP, as well as an unfavorable regulatory structure for CHP, it was determined that a 25 percent penetration factor would be used, providing a realistic estimate of the total amount of estimated CHP potential for Michigan.

There is a concern, however, that much of the identified CHP potential is at facilities related to the automotive industry, which is currently running at about 75 percent of capacity and is trending downward. Further, the difficulty of providing adequate incentives to a large number of major industrial firms, to cause them to make significant energy related investments when so many other factors affect the viability of their core business, must be recognized. Not all those facilities will choose to go forward with the development of CHP facilities, regardless of the economics. Experience has shown that it is often difficult for manufacturing facilities to adopt CHP technologies, regardless of the industry type.

[75] For information on existing CHP capacity in Michigan, refer to the CNF report, Appendix F, Pages F1-F5. (Available online at http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/othergen/finalreportjan_2006.pdf.

In addition, the CHP Team with the help of MPSC Staff mailed out a survey questionnaire to select, potential CHP candidates, in order to assess the barriers and issues to implementation of such CHP projects, and hence the market potential for future CHP. The results of the CHP survey and subsequent CHP assessment analysis can be found in Chapter 5A of Appendix Volume II which is the Combined Heat and Power (CHP) document. Survey respondents indicated that major impediments to adoption of CHP units include high fuel costs (typically, for natural gas) and utility standby rates.[76]

Given the dynamics presently affecting the automotive industry in particular and Michigan manufacturing in general, the CHP Team determined that for modeling purposes it would be prudent to reduce the amount of potential capacity from industrial and institutional facilities with large boilers to 180 MW. This is based on the assumption is that approximately 25 percent of all the candidate facilities would apply CHP technology, down from the 50 percent assumption made in the CNF study. Also, it should be noted that the facilities identified as potential candidates for CHP applications are overwhelmingly industrial operations. That is a result of the CHP Team focus on boilers that produce rather high temperature and pressure steam. In addition to those candidate facilities however, many institutional and commercial facilities may also be good candidates for CHP applications. Thus, the adoption rates modeled for the Plan are not as aggressive as they would first appear. Nevertheless, the CHP team believes the quantities presented for the Plan's expansion modeling are both technically and economically possible, but it should be understood that reaching this level of adoption would be a significant challenge and some important public policy changes, as discussed in the Policy document of Appendix Volume I, might be required in order to attract sufficient interest in the pursuit of these CHP opportunities.

2.2 Fuel Cell Technologies

In fuel cells, hydrogen and oxygen are separated by an electrolyte, inducing an electrochemical potential. The kind of electrolyte used determines the kind of chemical reactions that take place in the cell, the kind of catalysts required, the temperature range in which the cell operates, the fuel required, and other factors. These characteristics, in turn, affect the applications for which these cells are most suitable.

Fuel cell types include phosphoric aid, molten carbonate, solid oxide and proton exchange membrane. Phosphoric acid fuel cells and to a much smaller extent molten carbonate fuel cells, are available commercially now, and proton exchange membrane fuel cells have been used in a limited way in standby applications. Advances in other fuel cell technologies may enable their increased commercialization in the near future. The various types of fuel cells can be fueled by natural gas, hydrogen, biogas, methanol, or propane. Today however, hydrogen – usually extracted from natural gas – is the most commonly used source for fuel cells. Companies developing products for utilities and electric customers are concentrating on fuel cells that run on

[76] It should be noted that recent changes in wholesale markets could allow the option of purchasing standby power either through bilateral contracts with non-utility suppliers or through day-ahead or real-time wholesale markets. Thus, the impression that high utility standby rates remains an obstacle to CHP adoption needs to be reexamined and existing Michigan utility rates and tariffs for interconnected CHP systems may need to be revised to reflect current market conditions.

natural gas, but the automotive industry is investigating models that would run on gasoline or methanol. Appropriate applications of fuel cells include rural off-grid power supply, microgrids,[77] portable power generation, back-up for uninterrupted power needs, and other uses. See Chapter 5B of Appendix Volume I which is the Distributed Generation and Related Technologies Matrix document for additional details.

2.3 Reciprocating Engines

Most of us are familiar with reciprocating engines, such as those found in cars, trucks, light planes, or even trains. Annual North American production tops 35 million units for cars, trucks, heavy equipment, and a wide variety of power generation applications, from small backup power systems to utility-size units. For power generation, internal combustion (IC) engines benefit from having the lowest first cost, by being easy to start, and by being reliable when properly maintained. IC engines are well suited for standby, peaking, and intermediate power applications, as well as for combined heat and power in commercial, institutional, and light industrial applications of less than 10 MW. Two main IC engine types are used for power generation – the four-cycle, spark-ignition and the compression-ignition reciprocating engines. To date, reciprocating engines and CHP represent the DG options that have experienced the most significant commercial adoption. See Chapter 5B for additional details.

2.4 Stirling Engines

The Stirling engine was invented in the early 1800s by Robert Stirling, who sought to create a safer, more reliable alternative to traditional steam engines of the time. Stirling engines convert any temperature differential directly to movement: they use a displacer piston to move an enclosed gas back and forth between cold and hot reservoirs. At the hot reservoir, the air expands and pushes a power piston, producing work and displacing the air to the cold reservoir. There, the air contracts and pulls the power piston, effectively closing the cycle.

The Stirling engine itself is a heat recovery device, like the steam turbine. Stirling engines produce mechanical power not by explosive internal combustion, but using the heat produced by an external heat source. Until recently, however, reliability problems have limited their commercial application. Recent test results of "free-piston" Stirling engines have increased confidence in this technology. For example, one free-piston Stirling engine has demonstrated more than 50,000 hours of continuous operation on a single engine/alternator. This high level of availability, however, applies only to the Stirling generator and not the heat source. In addition, it is only in the past decade that a viable "free-piston" Stirling was developed. All Stirling engines can be operated on a wide variety of fuels. When used with fossil and biomass fuel, the continuous-combustion heater head avoids temperature spikes. Thus, in operation, Stirling engines can offer comparatively low emissions that are relatively easy to control. Stirling engines closely couple a burner to a heater-head heat exchanger. The exchanger induces harmonic oscillations in a piston that is placed inside a hermetically sealed container. The piston power is delivered directly by a conventional copper wound induction motor to produce

[77] The term microgrid refers to viewing individual distribute generators and their associated loads as a subsystem or microgrid. These microgrids require specific attention to operational details required to maintain the transmission grid's integrity.

alternating current power at any desired voltage. More details about Stirling engines can be found in Chapter 5B of Appendix Volume II.

2.5 Micro-turbines and Combustion Turbines

Micro-turbines are a relatively new technology, which is now making the transition to commercial markets. Micro-turbines can run on a variety of fuels, including natural gas, propane, and fuel oil. They consist of a compressor, combustor, turbine and generator. These very small turbines contain essentially one moving part and use either air or oil for lubrication. Micro-turbines require little maintenance, but usually need a major overhaul every four years. They can be used in a variety of applications, including baseload generation, peak shaving and cogeneration or CHP.

Combustion turbines, or gas turbines, consume large quantities of air, compress it and then mix with fuel in a combustor to generate hot gases. These hot gases are converted into useful work by a power turbine, which drives an attached generator to produce electricity. Combustion turbines are a proven industrial and utility technology ranging in size from 30 kilowatts (kW) to hundreds of MW. Emissions from these systems can be controlled to very low levels using dry combustion techniques, water or steam injection, or exhaust treatment. They also require less maintenance than reciprocating engines, and are generally smaller per MW and more modular in size/configuration Drawbacks include low efficiency at low power due to compressor losses, as well as extremely high combustion temperatures and high blade speeds and a higher first cost basis on units less than 25 MW, when compared to reciprocating engines. More details about micro-turbines and combustion turbines are provided in Chapter 5B of Appendix Volume II.

2.6 Advanced Storage and Battery Systems

Energy storage technologies are generally compared to the cost and performance of lead-acid batteries, since lead-acid batteries have been the standard for over 100 years. Today, there are various advanced battery systems available commercially for use in a variety of electricity storage applications, including balancing renewable energy production and cycling and short-duration emergency power back-up applications. These battery and related electricity storage options will likely play an important and increasing role in the future, in complementing distributed generation technologies and providing on-site energy options for customers. Technologies available include; lithium, nickel cadmium (NiCad), nickel metal hydride (NiMH), lead acid (sealed and flooded) and ultracapacitors. Many other alternative battery technologies exist. However, this report is limited to a discussion of the products most prevalent in the marketplace today and which are briefly summarized in Table 2.

Table 2: Basic Characteristics of Major Battery Types

	Battery System Type			
Characteristics	**Lead**	**Cadmium**	**NiMH**	**Lithium**
Negative electrode	Pb	Cd	H (as MH)	Li
Positive electrode	PbO_2	NIOOH	NIOOH	Lix COO_2
Electrolyte	H_2SO_4	KOH	KOH	PC OR DMC
Nominal voltage	2	1.2	1.2	4
Specific energy (Watt-hours per kilogram)	35	50	70	120
Energy density (Watt-hours per Liter)	70	75	170	200
Cycle life 80% DOD	150-300	1000+	1300	600
Source: *EPRI, Battery Storage: Big Opportunities on a Smaller Scale*, spring 2006. See link: http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2006-Spring/1013289_storage.pdf				

More details about the various battery and other storage systems investigated for the Plan are provided in Chapter 5B.

2.7 Current State of Alternative Generation Options

Combustion turbines and reciprocating engines are commercially available today. Fuel cells, though available, are relatively expensive for most distributed applications. Development work on several fuel cell designs is ongoing and improvements in efficiency and lower costs are likely in the near to intermediate-term future. Stirling engines are also available, although not widely adopted. Stirling engine development work continues to take place. Chapter 5B provides more information on the current and projected state of these generation technologies.

2.8 Current State of Energy Storage Options

Four battery technologies are commercially available in various sizes. Lithium ion batteries are used in cell phones and laptop computers because of their small size. Because of their light weight and high energy to weight ratio, lithium ion batteries are also being explored as a preferred option for use in hybrid electric vehicles.

NiMH is used in digital cameras because of its ability to recycle, as well as in hybrid vehicles for the same reason. In the stationary power market, NiMH is beginning to attract customers who are concerned more with life-cycle, rather than initial, costs. NiMH has a long calendar life, limited explosion hazard, is recyclable, and environmentally benign, and has a compact weight and volume. The chemistry of NiMH makes it an ideal battery for storage and recycling applications when used with wind, solar, or peak shaving applications. Cycled once daily, a NiMH battery operating in parallel with one of these generation technologies can be expected to last approximately seven years. A comparable lead acid battery will last only one year.

NiCad batteries have been in the market place for many years as an alternative to lead acid. Because of the environmental hazards associated with exposure to lead and cadmium, there are significant concerns regarding the proper recycling of NiCad and lead acid batteries.

In the near term, lead acid batteries will continue to dominate the battery market because they cost significantly less than NiMH. Many power systems have been developed to work with lead acid and lead acid manufacturers have an OEM (original equipment manufacturer) relationship in the industry to use sealed and valve regulated lead acid batteries with uninterrupted power systems (UPS). As other battery technologies become more available and economies of scale improve, the technologies may gain market share.

The opportunities in renewable energy systems for storage and recycling will be an advantage for NiMH. Recent issues with the volatility of lithium will have to be addressed for the public to be more confident of their use in larger applications. Automotive applications of advanced battery systems for hybrid automobiles should also boost markets for these technologies. Additional details regarding the various battery and electricity storage technologies are included in Chapter 5B.

2.9 Economic Considerations for DER Technologies

Cost is an important factor when considering the purchase of any technology, including DER technologies. However, determining the cost of a DER technology is often times complex and difficult. A unit’s cost includes equipment (or capital cost) and other expenses related to installing the equipment, and ongoing costs for operations and maintenance. The supplemental documents include estimated prices where available, associated with the DER technologies analyzed by the Workgroup.

As equipment production levels and sales increase, it is expected that economies of scale in manufacturing and deployment will result in decreased equipment costs. Installation costs can vary widely for a given technology especially for less prevalent technologies, and are often approximately 30 percent of the capital cost, but can equal or exceed capital costs for highly customized applications. Therefore, customers need to carefully consider the expected performance of a proposed DG system, along with its capital and operating costs, in order to determine whether the option is appropriate.

2.10 Environmental Impacts of DER Technologies

A description of each distributed energy resource’s air emissions profile and other environmental characteristics are included in Chapter 5B of Appendix Volume II. From that document, it is evident that most of these options have fairly low emissions characteristics, compared to existing central station power plants.

Environmentally, lead acid batteries contribute a significant portion of the lead and acid in the environment. Cadmium has similar disposal issues, and some countries have considered a ban on the cadmium in their landfills. NiMH batteries, on the other hand, are environmentally safe.

3. Smart Power Grid Technologies

Change brought on by national energy policy, market forces, technology and regulation are transforming the various components of our country's traditional electric infrastructure and the way the power grid is operated. For example, new regional commercial patterns are presently developing along with wholesale competition, and additional operational issues such as the deployment of distributed generation resources, are resurfacing. These changes have been underway for approximately the last 10 to 15 years and have drawn attention to the need for improved grid reliability, increased market efficiencies, enhanced customer value, and the application of a variety of new technologies.

Electric industry changes are also being driven by new technologies that are gradually beginning to transform the national power grid from one controlled and operated by electro-mechanical controls to micro processed digital devices. The "Smart Power Grid" is a general concept for this process of transforming the nation's electric power grid by applying computers, electronics, and advanced materials to implement advanced communications, automated controls, and other forms of information technology to improve the economics, reliability and safety of the grid. This vision of a smart power grid integrates energy infrastructure, processes, devices, information, and markets into a coordinated and collaborative process which will allow energy to be generated, distributed, and consumed more effectively and efficiently. Eventually, implementation of smart power grid architecture will enable devices at all levels within the grid (from power generator to customer) to communicate, independently sense, anticipate and respond to real-time conditions by accessing, sharing and acting on real-time information.

Planning, managing, and operating the electric power system in a coordinated and collaborative way can provide many benefits for both customers and power system providers, alike. Ideally, as new technologies become available, they will be integrated into the system where they can be shown to provide higher value. Not all of the technology advances currently envisioned are immediately available for implementation, though. Advanced smart power grid technologies are in many different stages of development and commercialization. Many will require further development, testing, and demonstration before they are ready to be deployed throughout the highly complex power grid, while others are available today. Incremental deployments of the new technologies will happen as their cost effectiveness is demonstrated and as industry participants agree to various applicable standards. Many stakeholder groups are currently involved in the process of organizing, studying, specifying, designing, testing and implementing the hardware and concepts of a Smart Power Grid through a variety of study groups, alliances, collaborative, and pilot projects.

Additional information on technology options, barriers to adoption, commercial readiness, and applications related to smart power grid architecture and communications is presented in Chapter 5C.

3.1 Technology Adoption Issues – Grid Interconnection

Grid interconnection policies were identified by participants in the Alternative Technologies Workgroup as a particularly important issue associated with the adoption of DG technologies. The Michigan Customer Choice and Electricity Reliability Act (2000 PA 141, Section 10e;

MCL 460.10e) directed the Michigan Public Service Commission to establish standards, "for the interconnection of merchant plants with the transmission and distribution systems of electric utilities … consistent with generally accepted industry practices and guidelines … established to ensure the reliability of electric service and the safety of customers, utility employees, and the general public."[78] The Commission subsequently developed Electric Interconnection Standards rules (R 460.481–460.489).[79]

Once the rules were fully developed, Michigan utilities filed interconnection procedures in concert with those rules.[80] These rules generally provide for the procedures Michigan's regulated electric distribution companies must employ when considering interconnection requests. They describe the required application process, basic technical criteria, filing fees, and deadlines for the completion of the various steps in the process. The criteria, procedures, and timelines vary for five different categories of generators, based on the size of the generators and the related complexity of the required interconnection and protective equipment. In reviewing technologies for consideration for Michigan's 21st Century Energy Plan, a critical assumption has been that all interconnections with the utility grid must meet all technical and safety requirements, and must always be operated in a manner that assures the reliability and safety of all utility grid and interconnected equipment and the health and safety of individuals who may come into contact with the grid and its interconnected equipment.

4. Conclusions

Among all the technologies analyzed by the Alternative Technologies Workgroup, only CHP is included in the expansion plan modeling, because it historically and continues to provide near-term contributions to Michigan's future electricity infrastructure.[81] Many of the other DG technologies explored for the Plan project can provide specialized applications for power needs, fill important, but limited capacity roles, or are continuing to undergo commercial development.

Similarly, Michigan utility companies are already engaged in a variety of projects that can reflect Smart Power Grid applications.[82] But, implementation of Smart Power Grid applications will be with incremental changes and adaptation over time

[78] http://www.legislature.mi.gov/(wgbxkq55zjnwtc2ym2nhu145)/mileg.aspx?page=getObject&objectName=mcl-460-10e.

[79] http://www.state.mi.us/orr/emi/admincode.asp?AdminCode=Single&Admin_Num=46000481&Dpt=&RngHigh=48702110.

[80] The utility procedures were approved in Cases Nos. U-14085 (for Northern States Power Company – Wisconsin, d/b/a.Xcel Energy), U-14091 (for Indiana Michigan Power Company, d/b/a American Electric Power), and U-14088 for all other utilities regulated by the Michigan PSC.

[81] Other forms of DG (reciprocating engines or Stirling engines) can be assumed to be captured as part of the Renewable Energy Workgroup's modeling estimates. The remainder of DG options studied are considered to be niche applications that are not readily commercially available at competitive prices.

[82] These projects are described in Chapter 5C of Appendix Volume 2 which is the Smart Power Grid and Related Technologies Supplemental Document attached to this report and also posted on the Plan website.

CHAPTER 5A

Estimate of CHP Potential – Alternative Technologies Workgroup

1. Introduction and Methodology

1.1 Introduction

The purpose of this supplemental document is to describe the methodology used to estimate the potential achievable new supply of electricity that could be reasonably developed over the next 10 years at Michigan's large industrial, institutional and commercial facilities.

1.2 Methodology

During the prior CNF process, the combined heat and power (CHP) Team was able to use boiler permit data from the Department of Labor and Economic Growth (DLEG) to identify the scope of Michigan's large and medium sized boilers. Unfortunately, the boiler permit database did not indicate the degrees to which boilers were actually in use, making it difficult to accurately calculate the capacity factors of the selected boilers. The CHP Team therefore had to rely on ad hoc information regarding which steam boilers were actually available to potentially add CHP systems.

Fortunately, during the 21st Century Energy Planning process, the CHP Team was able to obtain better data from the Michigan Department of Environmental Quality (MDEQ), Michigan Air Emissions Reporting System (MAERS) Database. This database not only has a comprehensive universe of industrial, institutional, and commercial boilers in its system, but it also indicates the type and amount of fuel they consumed in 2005. Using this fuel data, the CHP Team could calculate capacity factors for all boilers in use in 2005 – providing a major improvement in accuracy of the projected results.

Using the boilers database supplied by MDEQ, the CHP Team went through the following steps:

Step 1: Calculate Capacity Factors - The CHP Team calculated capacity factors for each boiler where both capacity and fuel usage was available in the MAERS database.

Step 2: Categorize Boilers by Size (MMBTUHR Capacity) – All boilers were first classified into the following categories:

- Industrial boilers
  - Large boilers (100+ MMBTUHR)
  - Medium boilers (26-99 MMBTUHR)
  - Small boilers (20-25 MMBTUHR)
  - Very small boilers (<20 MMBTUHR)
- Commercial boilers (including institutional and municipal)
- Other boilers (all boilers for which capacity factors could not be calculated)

A total of 884 boilers were considered as a result of Step 2.

Step 3: Sort Out Non-CHP Candidates Based on Location - The CHP Team reviewed each category and removed boilers located at:

- existing utilities, merchant plants or independent power producer facilities;
- known CHP sites; or
- steel mills.

Those boilers that used wood as a fuel were also excluded in this step, since these biomass fueled boilers are included in the state's renewable standard. A total of 228 boilers were excluded as a result of Step 3.

Step 4: Sort Out Non-CHP Candidates Based on Usage - Next, the CHP Team excluded most boilers that had one or more of the following concerns:

- questionable data;
- low pressures (<150 PSI);
- capacity factors less than 25 percent;
- consumed less than 50 MCF of natural gas (if capacity factor was unknown); and
- fueled with wood (this was transferred to the Renewable Energy Subgroup for inclusion in their analysis.

A total of 431 boilers were excluded as a result of Step 4.

Step 5: Sort for Economic Suitability - The CHP Team conducted a "positive sort" to select boilers that were located at businesses thought to be likely to adopt CHP due to business factors, or due to prior feasibility studies known to members of the Team. Rejected boilers were moved to the "Excluded" worksheet. A total of 225 industrial boilers were kept.

Step 6: Conducted CHP Supply Analysis - Once a dataset was established of potential boilers that were established in suitably located facilities and businesses considered more likely adopters of CHP, the Team summarized key information as presented in Table 1.
The CHP Team began to evaluate CHP electrical production potential. In this effort, it was assumed that natural gas boilers would be equipped with higher efficiency gas turbines, while boilers fueled with coal, oil, or other fuels would be equipped with steam turbines. It was further assumed that design megawatt (MW) capacity would exceed calculated output by 35 percent. The estimated kilowatt hours (kWh) of each category of boilers was then calculated at CHP "penetration rates" of 100 percent, 50 percent, and 27 percent. Effective heat rates and average MW/boiler estimates were also calculated for each category of boilers. The results of this analysis are provided in Table 1.

Estimates of additional CHP potential from three additional specific sources: new ethanol plants, steel mills, and cement kilns, were then added to Table 1 and this data is provided in Table 2. The CHP Team realizes each of these three sectors represent significant CHP potential, but the team was able to make only preliminary estimates of this potential, based upon prior knowledge of group members.

Table 1: Summary of Michigan Industrial Boiler Capacities – 2005

Industrial Boiler Type[1]	Size (MMBtu/Hr)	Number of Boilers	Average Design Capacity (MMBtu/Hr)	Average Hourly Output (MMBtu/Hr)	Estimated Capacity Factor (%)	Average Annual Throughput (MMBtu/Yr)
Large Boilers	100+	35	161.24	56.60	35.10%	495,792
Medium Boilers	25-100	75	57.26	19.50	34.05%	170,787
Small Boilers	20- 25	17	21.30	7.40	34.76%	64,848
Very Small Boilers	<20	33	12.88	8.56	66.43%	74,962
Commercial		18	18.00	13.42	52.57%	117,599
Other Boilers		47		15.18		133,010

Source: Michigan Department of Environmental Quality, Michigan Air Emissions Reporting System (MAERS) Database.
Note: [1] Excludes all wood-fired boilers (wood-fired boilers are discussed in the renewable energy resource assessment). Also excludes boilers that are reported in the MAERS database as: (a) operating under 150 PSI pressure; (b) with capacity factors 15 percent or less; (c) reporting low or no 2005 fuel usage; (d) located at non-functional sites; or (e) located at facilities with already existing CHP or utility/merchant power plant electricity production.

With the latter considerations in the forefront of the minds of the CHP Team, the Team projected that a 27 percent penetration, or, of 182 MW of new CHP was a reasonable and achievable as a 10 year CHP target if the economic, financial, and regulatory barriers become favorable. Until these barriers to CHP are addressed, more robust projections of CHP supply, especially units fueled by natural gas, would likely be unduly optimistic.

Table 2: CHP Potential (kW) from Michigan Industrial Boilers and Other Facilities

.

	CHP Potential		
	100% Market Penetration (kW)	**50% Market Penetration (kW)**	**27% Market Penetration (kW)**
Industrial Boilers[1]			
Large Boilers	160,337	80,168	43,291
Medium Boilers	113,217	56,608	30,569
Small Boilers	10,127	5,064	2,734
Very Small Boilers	25,702	12,851	6,940
Commercial	21,919	10,959	5,918
Other Boilers	57,874	28,937	15,626
Subtotal	**389,176**	**194,588**	**105,078**
135% Subtotal	**525,388**	**262,694**	**141,855**
Other Facilities			
Ethanol Facilities[2]	25,000	12,500	6,750
Steel Facilities[3]	100,000	50,000	27,000
Cement Kilns[4]	25,000	12,500	6,750
Subtotal	**150,000**	**75,000**	**40,500**
Total Michigan CHP Potential (kW)	**675,388**	**337,694**	**182,355**

Source: Michigan Department of Environmental Quality, Michigan Air Emissions Reporting System (MAERS) Database.

Notes: [1] CHP potential for boilers assumes a heat rate of 25,787 Btu/kWh.
[2] An average of 5 MW of CHP capacity is estimated for each of the five ethanol plants in operation or development.
[3] Data for steel facilities suggests nearly 94 MW of CHP capacity based on fuel usage, with a built ceiling of 125 MW.
[4] Data for cement kilns suggests nearly 58 MW of CHP capacity based on fuel usage, with a built ceiling of 80 MW.

2. Summary of CHP Industrial Survey

The CHP Team conducted a survey questionnaire of potential CHP candidates in order to assess the barriers and issues to implementation of such CHP projects, and hence the market potential for future CHP. Of the 24 questionnaires mailed, 13 completed forms were returned. The answers are compiled below in the format of the actual survey.

The summary of the results indicate that cost of natural gas fuel and utility standby power charges are a major prohibiting factor for CHP projects.

Alternative Technology CHP Industrial Survey Results

1. **<u>Has a business case analysis for CHP ever been performed for this location</u>?**

   Of the 13 completed forms 10 have replied that there has been some sort of analysis or building performed on their site. The overall response indicates that due to the price of gas this is a costly project. Four of the companies have shutdown their CHP project due to this high project cost. However, one company's utility system is based on CHP and has been since 1965.

   Of the 13 completed forms two have replied that there has not been a CHP case analysis done. Responses indicated current contracts do not allow this to happen.

   <u>If yes, would you be willing to share the approximate cost ($/MW) of the project and a copy of the report? (Note: if provided, this will be kept confidential by the MPSC)</u>.

   One company provided information. In 1993 their cost was approximately $7,000,000 for 3.8 MW

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2. **<u>Please identify any of the following that were identified or would likely be obstacles to developing a CHP project at this site</u>**. (The number of responses is shown to the left of the given obstacles and some companies have offered more than one obstacle.)

   3 - Insufficient steam demand on a year around basis
   2 - Length of contract or financing commitment required
   3 - Cost of new electric infrastructure at the site (including interconnections)
   2 - Environmental permitting issues for boiler modifications or other reasons
   4 - Cost of electric tariff and/or standby charges
   3 - Low cost of purchased price of electricity from utility or market
   0 - Personnel issues (hiring additional operators, increased O&M etc.)
   3 - Reliability issues associated with operating a CHP
   7 - Fuel price risk (volatility of natural gas or coal price)
   1 - Contractually prohibited (exclusive electric supplier, etc.)
   0 - Other

3. **<u>If the site does not have sufficient steam demand year around to support a CHP project, are there any processes that could be converted to steam usage (i.e. chillers, etc.) to increase steam demand</u>?**

   Of the 13 completed questionnaires one company has responded "yes" to this question. Their response indicates that they use air conditioning to increase steam demand.

   Of the 13 completed questionnaires three companies have replied "no" to this question, while eight had no response.

4. **<u>What approximate hurdle rate (internal rate of return) would your company require in order to implement a CHP project</u>?**

Of the 13 completed questionnaires five companies have responded. The approximate hurdle rate for these companies ranges from 15 - 45 percent.

5. **<u>If all roadblocks were removed and a favorable business case could be developed for CHP, would your company likely move forward with the project</u>?**

Of the 13 completed questionnaires eight have replied that they would move forward with the CHP project.

Of the 13 completed questionnaires one has replied that they would not continue with the project.

Of the 13 completed questionnaires four have offered no response to this question.

Chapter 5B

Distributed Generation and Technologies Matrix

Table 1: Fuel Cell Technology Comparisons

Phosphoric Acid Fuel Cell – Uses liquid phosphoric acid as the electrolyte. Electrodes are made of carbon paper coated with a finely-dispersed platinum catalyst. The catalyst strips electrons off hydrogen-rich fuel at the anode. Positively charged hydrogen ions then migrate through the electrolyte from the anode to the cathode. Electrons generated at the anode travel through an external circuit, providing direct current electric power, and return to the cathode. There, electrons, hydrogen ions and oxygen form clean water, which is discharged from the cell.

Molten Carbonate Fuel Cell – Uses an electrolyte made of lithium-potassium carbonate salts heated to about 1,200°F (650°C). At these temperatures, the salts remain in a molten state that can conduct charged particles, called ions, between two porous electrodes.

Molten carbonate fuel cells eliminate the external fuel processors that lower temperature fuel cells need to extract hydrogen from the fuel. When natural gas is the fuel, methane (the main ingredient of natural gas) and steam are converted into a hydrogen-rich gas inside the fuel cell stack (a process called "internal reforming"). At the anode, hydrogen reacts with the carbonate ions to produce water, carbon dioxide, and electrons. The electrons travel through an external circuit, creating electricity, and return to the cathode. There, oxygen from the air and carbon dioxide recycled from the anode react with the electrons to form carbonate ions that replenish the electrolyte and provide ionic conduction through the electrolyte, completing the circuit.

Solid Oxide Fuel Cell – Composed of all-solid-state materials, the anode, cathode and electrolyte are all made from ceramic substances. Because of the all-ceramic make-up, the cells can operate at temperatures as high as 1,800°F (1000°C). These cells can be configured as either rolled tubes or flat plates, and are manufactured using many of the techniques currently employed in the electronics industry.

Although a variety of oxide combinations have been used for SOFC electrolytes, the most common has been doping zirconia with yttria, which facilitates the transport of oxygen ions. Formed as a crystal lattice, the hard ceramic electrolyte is coated on both sides with specialized porous electrode materials.

At the high operating temperatures, oxygen ions are formed at the "air electrode" (the cathode). When a fuel gas containing hydrogen is passed over the "fuel electrode" (the anode), the oxygen ions migrate through the crystal lattice to oxidize the fuel. Electrons generated at the anode move out through an external circuit, creating electricity. Reforming natural gas or other hydrocarbon fuels to extract the necessary hydrogen can be accomplished within the fuel cell, eliminating the need for an external reformer.

Alkaline Fuel Cell – Alkaline Fuel Cells (AFC) use a solution of potassium hydroxide in water as the electrolyte and can use a variety of non-precious metals as a catalyst at the anode and cathode.

AFCs' high performance is due to the rate at which chemical reactions take place in the cell.

The disadvantage of this fuel cell type is that it is easily poisoned by carbon dioxide (CO_2). In fact, even the small amount of CO_2 in the air can affect this cell's operation, making it necessary to purify both the hydrogen and oxygen used in the cell.

Other disadvantages are the costs and material durability issues. Cost is less of a factor for remote locations such as space or under the sea. However, to effectively in most mainstream commercial markets, these fuel cells will have to become more cost-effective. To be economically viable in large-scale utility applications, fuel cells need to reach operating times exceeding 40,000 hours, something that has not yet been achieved due to material durability issues.

Proton Exchange Membrane Fuel Cell – Polymer electrolyte membrane (PEM) fuel cells—also called proton exchange membrane fuel cells—deliver high power density and offer the advantages of low weight and volume, compared to other fuel cells. PEM fuel cells use a solid polymer as an electrolyte and porous carbon electrodes containing a platinum catalyst. They need only hydrogen, oxygen from the air, and water to operate and do not require corrosive fluids like some fuel cells. They are typically fueled with pure hydrogen supplied from storage tanks or onboard reformers.

Polymer electrolyte membrane fuel cells operate at relatively low temperatures, around 80°C (176°F). Low temperature operation allows them to start quickly (less warm-up time) and results in less wear on system components, resulting in better durability. However, it requires that a noble-metal catalyst (typically platinum) be used to separate the hydrogen's electrons and protons, adding to system cost. The platinum catalyst is also extremely sensitive to CO poisoning, making it necessary to employ an additional reactor to reduce CO in the fuel gas if the hydrogen is derived from an alcohol or hydrocarbon fuel. This also adds cost. Developers are currently exploring platinum/ruthenium catalysts that are more resistant to CO.

PEM fuel cells are used primarily for transportation applications and some stationary applications. Due to their fast startup time, low sensitivity to orientation, and favorable power-to-weight ratio, PEM fuel cells are particularly suitable for use in passenger vehicles, such as cars and buses.

A significant barrier to using these fuel cells in vehicles is hydrogen storage. Most fuel cell vehicles (FCVs) powered by pure hydrogen must store the hydrogen onboard as a compressed gas in pressurized tanks. Due to the low energy density of hydrogen, it is difficult to store enough hydrogen onboard to allow vehicles to travel the same distance as gasoline-powered vehicles before refueling, typically 300-400 miles. Higher-density liquid fuels such as methanol, ethanol, natural gas, liquefied petroleum gas, and gasoline can be used for fuel, but the vehicles must have an onboard fuel processor to reform the methanol to hydrogen. This increases costs and maintenance requirements. The reformer also releases carbon dioxide (a greenhouse gas), though less than that emitted from current gasoline-powered

Direct Methanol Fuel Cell – Most fuel cells are powered by hydrogen, which can be fed to the fuel cell system directly or can be generated within the fuel cell system by reforming hydrogen-rich fuels such as methanol, ethanol, and hydrocarbon fuels. Direct methanol fuel cells (DMFCs), however, are powered by pure methanol, which is mixed with steam and fed directly to the fuel cell anode.

Direct methanol fuel cells do not have many of the fuel storage problems typical of some fuel cells since methanol has a higher energy density than hydrogen—though less than gasoline or diesel fuel. Methanol is also easier to transport and supply to the public using our current infrastructure since it is a liquid, like gasoline.

Direct methanol fuel cell technology is relatively new compared to that of fuel cells powered by pure hydrogen, and DMFC research and development are roughly 3-4 years behind that for other fuel cell types.

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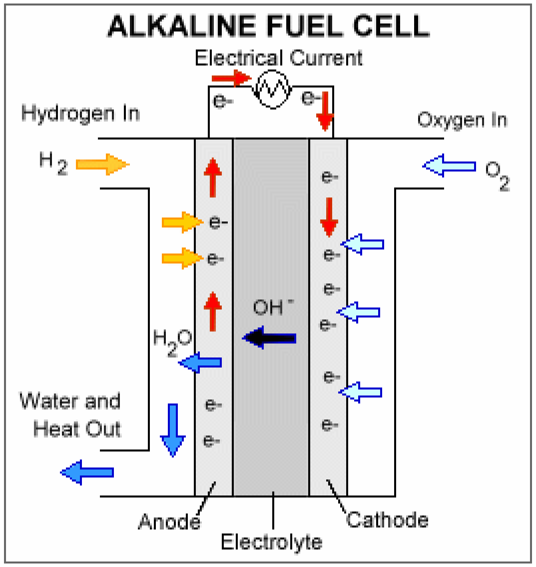
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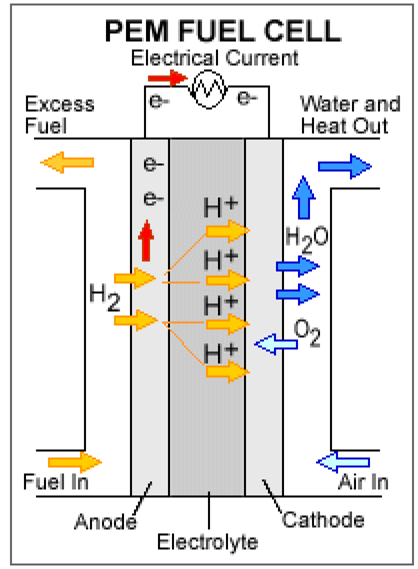
PEM FUEL CELL
Electrical Current
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Anode
Electrolyte
Cathode

Table 1: Fuel Cell Technology Comparisons (Part 1 of 4)

Technology Type	Fuel Type(s)	Unit Capacity (kW)	Current Status			
			Installed Cost ($/kW)1	Electrical Efficiency (%, HHV/LHV)2	Heat Rate (BTU/kWh)	Net Efficiency (%, Electrical + Thermal)
Phosphoric Acid	Hydrogen (external reforming)	50 kW – 1 MW (200 kW typical)	$4,000/kW – $4,500/kW	36% – 42%	8,000 – 9,500 BTU/kWh	80% – 85%
Molten Carbonate	Natural gas, propane, LPG, syngas (internal reforming)	<1 kW – 1 MW (250 kW typical)	>$5,000/kW	50% – 60%	5,700 – 6,800 BTU/kWh	85%
Solid Oxide Fuel Cell	Natural gas, propane, LPG, syngas (internal reforming)	5 kW – 3 MW	$3,500/kW – $4,000/kW	50% – 70%	4,900 – 6,800 BTU/kWh	80% – 85%
Alkaline	Hydrogen (external reforming)	10 kW – 100 kW		60% – 70%	4,900 – 5,700 BTU/kWh	NA
Proton Exchange	Hydrogen (external reforming)	<1 kW – 250 kW	$3,000/kW - $3,500/kW	50% – 60%	4,900 – 6,800 BTU/kWh	NA
Direct Methanol Fuel Cell	Methanol (internal reforming)	< 1 W – 100 W	NA	NA	NA	NA

Notes: [1] Installed Costs are "Overnight costs", and do not include financing costs.

[2] HHV (higher heating value) is the maximum potential energy released during complete oxidation of a unit of fuel and LHV (lower heating value) is the net energy released during oxidation of a unit of fuel. LHV= HHV- 21.998 (H) - 2.444 (W).

Table 1: Fuel Cell Technology Comparisons (Part 2 of 4)

Technology Type	Current Status					
	Operating Temperature (°Centigrade)	**Quantity/Quality of Waste Heat (e.g., lbs./hr steam, at what temperature)**	**Reactive Power[1] (Y/N)**	**In-Rush Capability (kW?)**	**Fuel Cost ($/kWh)**	**Levelized Cost ($/kWh)**
Phosphoric Acid	100 - 200 °C (~ 300 - 400 °F)	Can be converted to steam for space and water heating.	Y [2]	Y [3]	$0.035/kWh	NA
Molten Carbonate	600 - 700 °C (1112 - 1292 °F)	Can be used in CHP applications and CC electric power plants.	Y [2]	Y [3]	$0.03/kWh	$0.130/kWh - $0.173/kWh
Solid Oxide	650 to 1000 °C (1202 to 1832 degrees F)	Can be used in CHP applications and CC electric power plants	Y [2]	Y [3]	$0.03/kWh	NA
Alkaline	High temp: 100 - 250°C (212 - 482°F). Low temp: 23 - 70°C (74 -158°F)	NA	Y [2]	Y [3]	NA	NA
Proton Exchange	50 to 100 °C (122 - 212 °F)	NA	Y [2]	Y [3]	$0.04/kWh	$0.133/kWh - $0.186/kWh
Direct Methanol	60 to 90 °C	NA	Y [2]	Y [3]	NA	NA

Notes: [1] "Reactive Power" is the extent to which this facility type might produce (and/or require) ancillary services, such as Reactive Power.

[2] In order to provide reactive, power, fuel cells must be integrated with power inverters (that is, devices that convert power from direct current to alternating current), which can be made capable of providing reactive power management functions.

[3] In order to provide in-rush capability, fuel cells must be integrated with energy storage (e.g., batteries) of sufficient capacity.

Table 1: Fuel Cell Technology Comparisons
(Part 3 of 4)

Technology Type	Projected 2010[1]			Projected 2024[1]		
	Installed Cost ($/kW)	**Electrical Efficiency (%, LHV)**	**Levelized Cost ($/kWh)**	**Installed Cost ($/kW)**	**Electrical Efficiency (%, LHV)**	**Levelized Cost ($/kWh)**
Phosphoric Acid	3,200 – 3,600	36% – 42%	NA	2,500 – 3,000	36% – 42%	NA
Molten Carbonate	> 5,000	50% – 60%	0.097 - 0.115	>5,000	50% – 60%	0.075 - 0.093
Solid Oxide	3,000 – 3,500	50% – 70%	0.096	2,500 –3,000	50% – 70%	0.081
Alkaline	NA	60% – 70%	NA	NA	60% – 70%	NA
Proton Exchange	2,500 - 3,000	50% – 60%	0.101 - 0.138	1,500 - 2,000	50% – 60%	0.076 - 0.096
Direct Methanol	NA	NA	NA	NA	NA	NA

Table 1: Fuel Cell Technology Comparisons (Part 4 of 4)

Technology Type	Applications[1]	Technology & Market Challenges[1]	Commercial Status / # of Units Deployed[1]	Leading Manufacturers[1]	Manufacturing Locations[1]	Other Comments[1]
Phosphoric Acid Fuel Cell	Electric utility support	-Requires expensive (platinum) catalysts -Low current and low power -Large size/footprint -Heavy	Commercial >250 globally	United Technologies (IFC)	Connecticut	None
Molten Carbonate Fuel Cell	-Electric utility support -Large-scale distributed generation -Baseload power	-Durability of cell components is low due to high temperature of operation -Complex electrolyte management -Slow start-up -Poor cycling	Pre-Commercial >50 globally	Fuel Cell Energy	NA	NA
Solid Oxide Fuel Cell	-Auxiliary power -Electric utility support -Large-scale distributed generation Baseload power	-Durability of cell components is low due to high temperature of operation -Slow start-up -Poor cycling	Pre-Commercial >250 globally	-Acumentrics -Fuel Cell Technologies -Siemens -Quantum Fuel Systems (Global Thermoelectric) -Sulzer Hexis -Ceramic Fuel Cells Ltd (CFC) -Solid Oxide Fuel Cell, Company (SOFCo) -Rolls Royce Fuel Cell	Switzerland Australia Ohio Massachusetts	None

Technology Type	Applications[1]	Technology & Market Challenges[1]	Commercial Status / # of Units Deployed[1]	Leading Manufacturers[1]	Manufacturing Locations[1]	Other Comments[1]
Alkaline Fuel Cell	Niche transportation applications, including spacecraft, motorbikes, forklift trucks, marine and submarine applications.	-Operating times not yet maximized due to material durability issues. -Susceptibility to CO_2 poisoning decreases lifetime. -Low cost effectiveness in commercial markets.	Commercial <50 globally	-Eneco -Apollo Energy Systems -Astris Energi -Hydrocell -Industrial Research -NASA	NA	NA
Proton Exchange Fuel Cell	-Back-up power: telecom, data centers -Portable applications – cell phones, laptops, etc. -Small-scale distributed generation -Vehicles	Hydrogen storage issues.	Commercial >750 globally	-PlugPower -Avista Labs -Ballard -IdaTech -Intelligent Energy -Mitsubishi Heavy Industries -Nuvera -Teledyne -United Technologies (IFC) -Distributed Energy Systems (Proton Energy) -Hydrogenics,	New York Washington Vancouver U.K. Connecticut Ontario Idaho	None
Direct Methanol Fuel Cell	Portable applications – cell phones, laptops, etc.	NA	Not commercial	NA	NA	NA

Table 2: Reciprocating Engine Technology Comparisons

Reciprocating Engines – Most commonly found in cars, trucks, light planes, or even trains. Annual North American production tops 35 million units for cars, trucks, heavy equipment, and a wide variety of power generation applications, from small backup power systems to utility-size units. For power generation, internal combustion (IC) engines benefit from having the lowest first cost, by being easy to start, and by being reliable when properly maintained. IC engines are well suited for standby, peaking, and intermediate power applications, as well as for combined heat and power in commercial, institutional, and light industrial applications of less than 10 MW. These units are also used as Baseload applications at land-fill gas sites. Two main IC engine types are used for power generation – the four-cycle, spark-ignition engine, and the compression-ignition reciprocating engine. To date, reciprocating engines and combined heat and power (CHP) represent the distributed generation (DG) options that have experienced the most significant commercial adoption.

Table 2: Reciprocating Engine Technology Comparisons
(Part 1 of 6)

Technology Type - Reciprocating Engine[1]	Unit Capacity (kW)	Current Status						
		Installed Cost ($/kW)[2]	Electrical Efficiency (%, HHV/LHV)[3]	Heat Rate (BTU/kWh)	Net Efficiency (%, Electrical + Thermal)	Waste Heat Temperature (degrees Centigrade)	Quantity/Quality of Waste Heat (e.g., lbs./hr steam, at what temperature)
Natural Gas Type 1 Rich Burn 3 Way NSCR (CHP where different)	85 d/	$1,250 d/	28/31% (29/32%) d/	12,216 (4,704) d/	77% d/	93	Hot Water d/
Natural Gas/Type2 Rich Burn 3 Way NSCR (CHP where different)	100 a/	$1,126 ($1,475) ac/	30/33% a/	11,500 (4,879) a/	76% ac/	88 – 99 C a/	Hot Water a/
Natural Gas/Type3 Lean Burn (CHP where different)	1,000	$787 (1,027) a/	34/38% a/	10,035 (5,394) a/	71a/	88 – 99 C a/	Hot Water a/
Natural Gas/Type4 Lean Burn (CHP where different)	3000 a/	$776 (1,022) a/	35/39% a/	9,700 (5,599) a/	69% a/	88 – 99 C a/	Hot Water a/
Natural Gas/Type5 Lean Burn (CHP where different)	5000 a/	$759 ($973) a/	37/41% a/	9,213 (5,049) a/	73% ac/	88 – 99 C a/	Hot Water a/
Natural Gas/Type6 Lean Burn (CHP where different)	7000	$750 ($965) f/	41/45% e/	8,415 (4,839)	74% e/	88 – 99 C e/	Hot Water e/

Notes: [1] Reciprocating engine generator set (prime power, not standby)

[2] Installed Costs are “overnight costs” and do not include financing costs.

[3] HHV (higher heating value) is the maximum potential energy released during complete oxidation of a unit of fuel and LHV (lower heating value) is the net energy released during oxidation of a unit of fuel. LHV= HHV- 21.998 (H) - 2.444 (W).

Table 2: Reciprocating Engine Technology Comparisons (Part 2 of 6)

Technology Type - Reciprocating Engine[1]	Current Status					
	Reactive Power (Y/N)[2]	Annual Availability (%)[3]	Annual Forced Outage Rate[4] (%)	Capacity Factor[5] (annual average %)	Load Following Capability[6]	In-Rush Capability (kW?)
Type 1 Rich Burn 3 Way NSCR (CHP where different)	Y/N d/ Synchronous or induction generator models available	92 % d/	4 % d/	92 % b/	Y d/	Y d/
Type 2 Rich Burn 3 Way NSCR (CHP where different)	Y a/	90 – 95% a/	2 – 6 % a/	90 – 95% a/	Y a/	Y a/
Type 3 Lean Burn (CHP where different)	Y a/	90 – 95% a/	2 – 6 % a/	90 – 95% a/	Y a/ But limited d/	Y a/ but limited d/
Type 4 Lean Burn (CHP where different)	Y a/	90 – 95% a/	2 – 6 % a/	90 – 95% a/	Y a/	Y a/
Type 5 Lean Burn (CHP where different)	Y a/	90 – 95% a/	2 – 6 % a/	90 – 95% a/	Y a/	Y a/
Type 6 Lean Burn (CHP where different)	Y e/	92% e/	4 % e/	92% e/	Y e/	Y e/

Notes:
1. Reciprocating engine generator set (prime power, not standby)
2. "Reactive Power" is the extent to which this facility type might produce (and/or require) ancillary services, such as Reactive Power. If other ancillary services are important for this technology, either because it is capable of producing them or it requires them, please describe.
3. Percent of time unit is available, not considering planned outages.
4. Percent of time unit is unavailable due to unplanned outages.
5. Percent of time unit is available due to resource limitations (wind, solar)
6. Can these units follow load increases/decreases.

Table 2: Reciprocating Engine Technology Comparisons (Part 3 of 6)

Technology Type - Reciprocating Engine[1]	Current Status					
	Fuel Cost ($/kWh)	Fixed O&M Cost ($/kWh)	Variable O&M Cost ($/kWh)	Levelized Cost ($/kWh)	Lead Time: order to install (Months)	Longevity/ Durability (Months)
Type 1 Rich Burn 3 Way NSCR (CHP where different)	$0.0855 (0.033) d/	$0.0044 d/	$0.0110 d/	$0.111 (0.059) d/	6 months d/	180 months d/
Type 2 Rich Burn 3 Way NSCR (CHP where different)	$0.081 (0.034) ac/	$0.003 a/	$0.017 a/	$0.109-0.115 ($.066 to .073) a/	6 months d/	180 months
Type 3 Lean Burn (CHP where different)	$0.07 (0.038)ac/	$0.001 a/	$0.009 a/	$0.086-0.090 ($.056 to .061) a/	6 to 12 months d/	180 months
Type 4 Lean Burn (CHP where different)	$0.068(0.039) a/	$0.0014 a/	$0.0085 a/	$0.084 (0.057) a/	12 to 18	180 months d/
Type 5 Lean Burn (CHP where different)	$0.064 (0.035) ac/	$0.0011 a/	$0.0076 a/	$0.080 ($.052) a/	12 to 18	180 months
Type 6 Lean Burn (CHP where different)	$0.059 (0.034) ec/	$0.0009 e/	$0.0066 e/	$0.073 ($.049)e/	12 to 18	180 months

Notes: [1] Reciprocating engine generator set (prime power, not standby)

Table 2: Reciprocating Engine Technology Comparisons (Part 4 of 6)

Technology Type - Reciprocating Engine[1]	Current Status – Criteria Emissions (lb/MWh)							
	CO	**NO_x**	**SO_x**	**PM**	**PM 10**	**PM 2.5**	**Pb**	**VOCs (non methane)**
Type 1 Rich Burn 3 Way NSCR (CHP where different)	Able to meet SCAQMD 2006[2] standards of							
	1.77	0.44	Nil	NA	NA	NA	Nil	.44
Type 2 Rich Burn 3 Way NSCR (CHP where different)	Able to meet SCAQMD 2006 standards of							
	1.77	0.44	Nil	NA	NA	NA	Nil	.44
Type 3 Lean Burn (CHP where different)	Without SCR or oxidation catalyst							
	5.91	2.95	Nil	NA	NA	NA	Nil	2.95
Type 4 Lean Burn (CHP where different)	Without SCR or oxidation catalyst							
	7.38	2.07	Nil	NA	NA	NA	Nil	3.84
Type 5 Lean Burn (CHP where different)	Without SCR or oxidation catalyst							
	7.09	1.48	Nil	NA	NA	NA	Nil	1.48
Type 6 Lean Burn (CHP where different)	Without SCR or oxidation catalyst							
	7.09	1.48	Nil	NA	NA	NA	Nil	1.48

Notes: [1] Reciprocating engine generator set (prime power, not standby)
[2] SCAQMD 2006 – South Coast Air Quality Management District Rule 2006

Table 2: Reciprocating Engine Technology Comparisons (Part 5 of 6)

Technology Type - Reciprocating Engine[1]	Projected 2010[1]				Projected 2024[1]			
	Installed Cost ($/kW)	Electrical Efficiency (%, LHV)	Availability (%)	Levelized Cost ($/kWh)	Installed Cost ($/kW)	Electrical Efficiency (%, LHV)	Availability (%)	Levelized Cost ($/kWh)
Type 1 Rich Burn 3 Way NSCR (CHP where different)	NA	NA	NA	NA	NA	NA	NA	NA
Type 2 Rich Burn 3 Way NSCR (CHP where different)	$917	35%	92%	$0.098	$834	36%	92%	$0.094
Type 3 Lean Burn (CHP where different)	$737	42%	92%	$0.079	$703	44%	92%	$0.075
Type 4 Lean Burn (CHP where different)	$722	43%	92%	$0.076	$689	45%	92%	$0.073
Type 5 Lean Burn (CHP where different)	$696	45%	92%	$0.073	$649	50%	92%	$0.067
Type 6 Lean Burn (CHP where different)	NA	NA	NA	NA	NA	NA	NA	NA

Notes: [1] Reciprocating engine generator set (prime power, not standby)

Table 2: Reciprocating Engine Technology Comparisons (Part 6 of 6)

Technology Type – Reciprocating Engine[1]	Applications	Technology & Market Challenges	Commercial Status / # of Units Deployed	Leading Manufacturers	Manufacturing Locations	Other Comments
Type 1 Rich Burn 3 Way NSCR (CHP where different)	Most economical in base load CHP application where thermal energy is fully utilized. Hot water output ideal for laundry, washing applications, boiler feedwater heating, and absorption chiller. Multiple units can be teamed together for very high reliability and availability.	Technology is proven. Longer valve life and lower maintenance costs are being developed. Interconnection to utility frequently a hindrance. End users generally prefer to invest in items core to their business instead of power generation.	Commercial About 15 units in the field.	IPower Energy Systems	Indiana	In the future air emissions for these units will be much less than shown above.
Type 2 Rich Burn 3 Way NSCR (CHP where different)	Most economical in base load CHP application where thermal energy is fully utilized. Hot water output ideal for laundry, washing applications, boiler feedwater heating, and absorption chiller. Multiple units can be teamed together for very high reliability and availability.	Technology is proven. Longer valve life and lower maintenance costs are being developed. Interconnection to utility frequently a hindrance. End users generally prefer to invest in items core to their business instead of power generation.	Commercial. Many units in the 60– 120 kW range, primarily CHP applications in the field	Tecogen, IPower Energy Systems, Coast Intelligen	New Jersey, Indiana, Nevada	In the future air emissions for these units will be much less than shown above.

Technology Type – Reciprocating Engine[1]	Applications	Technology & Market Challenges	Commercial Status / # of Units Deployed	Leading Manufacturers	Manufacturing Locations	Other Comments
Type 3 Lean Burn (CHP where different)	Most economical in base load CHP application where thermal energy is fully utilized. Hot water output ideal for laundry, washing applications, boiler feedwater heating, and absorption chiller.	Technology is proven. Interconnection to utility frequently a hindrance. End users generally prefer to invest in items core to their business instead of power generation.	Commercial. Many units in the field.	Northern Power, Jenbacher, Caterpillar, Cummins, Waukesha, Deutz, Major engine/generator distributors		Urea and ammonia SCR systems for further control of emissions are unwieldy for this size system.
Notes: [1] Reciprocating engine generator set (prime power, not standby)						

Sources:

a) L. Goldstein, B. Hedman, D. Knowles, S. I. Freedman, R. Woods., and T. Schweizer, "Gas-Fired Distributed Energy Resource Technology Characterizations". National Renewable Energy Laboratory, Golden, Colorado. November 2003. (TP-620-34783). Cost data in 2003 dollars escalated to 2006 dollars by 3 percent inflation for three years.

b) DTE Energy Technologies, Inc. internal data.

c) Calculated from other data and using natural gas price assumption of $7.00 per MCF (1,030,000 BTU HHV)

d) Vendor (IPower Energy Systems, LLC - Anderson, Indiana) provided data.

e) Wartsila technical specifications (www.wartsila.com), April 2006.

f) Cost data extrapolated to larger sizes from L. Goldstein, B. Hedman, D. Knowles, S. I. Freedman, R. Woods., and T. Schweizer, "Gas-Fired Distributed Energy Resource Technology Characterizations". National Renewable Energy Laboratory, Golden, Colorado. November 2003.

g) Expect data for 7 MW Wartsila Model 34 SG to be similar to 5 MW Wartsila Model 34 SG included in L. Goldstein, B. Hedman, D. Knowles, S. I. Freedman, R. Woods., and T. Schweizer, "Gas-Fired Distributed Energy Resource Technology Characterizations". National Renewable Energy Laboratory, Golden, Colorado. November 2003. Wartsila technical specifications (www.wartsila.com), April 2006.

Table 3: Stirling Engine Technology Comparisons

Stirling Engine: Stirling engine is typically associated with external combustion piston engines, whose heat-exchange process allows for near-ideal efficiency in conversion of heat into mechanical movement. This occurs by following the Carnot cycle as closely as is practical with given materials. Coupled with an electric generator, a Stirling engine can convert heat into electrical power. Intended applications include use with renewable fuels and to serve distributed stationary power generation applications.

Any temperature difference will power a Stirling engine, so the term "external combustion engine" often applied to it is misleading. A heat source may be the result of combustion but can also be solar, geothermal, or nuclear or even biological. Likewise a "cold source" below the ambient temperature can be used as the temperature difference. A cold source may be the result of a cryogenic fluid or iced water. Since small differential temperatures require large mass flows, parasitic losses in pumping the heating or cooling fluids rise and tend to reduce the efficiency of the cycle.

Because a heat exchanger separates the working gas from the heat source, a wide range of combustion fuels can be used, or the engine can be adapted to run on waste heat from some other process. Since the combustion products do not contact the internal moving parts of the engine, a Stirling engine can run on landfill gas containing siloxanes without the accumulation of silica that damages internal combustion engines running on this fuel. The life of lubricating oil is longer than for internal-combustion engines.

The U.S. Department of Energy in Washington, NASA Glenn Research Center in Cleveland, and Stirling Technology Co. of Kennewick, Wash., are developing a free-piston Stirling converter for a Stirling Radioisotope Generator. This device would use a plutonium source to supply heat.

The potential also exists for nuclear powered Stirling engines in electric power generation plants. Replacing the steam turbines of nuclear power plants with Stirling engines would greatly simplify the plant, yield greater efficiency, and provide a much greater margin of safety, while reducing radioactive by-products.

Some Stirling engine designs require both input and output heat exchangers, which must contain the pressure of the working fluid, and which must resist any corrosive effects due to the heat source. These increase the cost of the engine, especially when they are designed to the high level of "effectiveness" (heat exchanger efficiency) needed for optimizing fuel economy. Fuel economy may not be an issue considering the advantages of using unlimited but unusual fuel sources that are available for a Stirling engine.

Due to heat exchangers, Stirling engines that run on small temperature differentials are quite large for the amount of power that they produce. Increasing the temperature differential allows for smaller Stirling engines that produce more power.

Dissipation of waste heat is especially complicated because the coolant temperature is kept as low as possible to maximize thermal efficiency. This drives up the size of the radiators markedly, which can make packaging difficult. This has been one of the factors limiting the adoption of Stirling engines as automotive prime movers. (Conversely, it is convenient for domestic or business heating systems where combined heat and power (CHP) systems show promise.

A "pure" Stirling engine cannot start instantly; it literally needs to "warm up". This is true of all external combustion engines, but the warm up time may be shorter for Stirlings than for others of this type, such as steam engines. Stirling engines are best used as constant run, constant speed engines.
Power output of a Stirling is constant and hard to change rapidly from one level to another. Typically, changes in output are achieved by varying the displacement of the engine (often through use of a swashplate crankshaft arrangement) or by changing the mass of entrained working fluid (generally helium or hydrogen). This property is less of a drawback in hybrid electric propulsion or base load utility generation where a constant power output is actually desirable.

Hydrogen's low molecular weight makes it the best working gas to use in a Stirling engine. As a tiny molecule, however, it is difficult to keep hydrogen inside the engine and, therefore, auxiliary systems usually need to be added to maintain the proper quantity of working fluid. These systems can be as simple as a gas storage bottle or as complicated as a gas generator. In any event, they add weight, increase cost, and introduce some undesirable complications. Some engines use air as the working fluid which is less thermodynamically efficient but avoids loss problems. Most technically advanced Stirling engines like those developed for United States government labs use helium as the working gas, because it functions close to the efficiency of hydrogen with fewer of the material containment issues.

Market Challenges: 1)Spark spread (i.e. cost of natural gas relative to cost of grid electricity) and 2) Market acceptance of new product.

Sources: Dave Miklosi, STM Power, 7/26/06

http://www.stmpower.com/
http://www.whispergen.com/main/acwhispergen/
http://www.sunpower.com/
http://www.stirlingenergy.com/
http://en.wikipedia.org/wiki/Stirling_engine

Table 3: Stirling Engine Technology Comparisons (Part 1 of 6)

Technology Type	Unit Capacity (kW)	Current Status						
		Installed Cost ($/kW)[1]	Electrical Efficiency (%, HHV/LHV)[2]	Heat Rate (BTU/kWh)	Net Efficiency (%, Electrical + Thermal)	Waste Heat Temperature (degrees Centigrade)	Quantity/Quality of Waste Heat (e.g., lbs./hr steam, at what temperature)
Stirling Engine Natural Gas	55	$1218/kW	29% (LHV)	11,800	80	58 ^{o}C	330,000 BTU/hr
Stirling Engine Bio Gas	55	$1218/kW	29% (LHV)	12,200	78	58 ^{o}C	330,000 BTU/hr

Notes: [1] Installed Costs are "overnight costs" and do not include financing costs.
[2] HHV (higher heating value) is the maximum potential energy released during complete oxidation of a unit of fuel and LHV (lower heating value) is the net energy released during oxidation of a unit of fuel. LHV= HHV- 21.998 (H) - 2.444 (W).

Table 3: Stirling Engine Technology Comparisons (Part 2 of 6)

Technology Type	Current Status					
	Reactive Power (Y/N)[1]	Annual Availability (%)	Annual Forced Outage Rate (%)	Capacity Factor (annual average %)	Load Following Capability	In-Rush Capability (kW?)
Stirling Engine Natural Gas	Y	95%	5%	NA	N	Y
Stirling Engine Bio- Gas	Y	95%	5%	NA	N	Y

Notes: [1] "Reactive Power" is the extent to which this facility type might produce (and/or require) ancillary services, such as Reactive Power.

Table 3: Stirling Engine Technology Comparisons (Part 3 of 6)

Technology Type	Current Status						
	Fuel Cost ($/kWh)	Fixed O&M Cost ($/kWh)	Variable O&M Cost ($/kWh)	Levelized Cost ($/kWh)	Lead Time – order to install (Months)	Longevity/ Durability (Months)	Footprint (ft^2/kW)
Stirling Engine Natural Gas	Dependent on installation, project, and region of globe	$0.008/kWh	None	NA	3	With regular maintenance, no known limit	0.435
Stirling Engine Bio- Gas	If renewable, fuel is usually "free."	$0.008/kWh	None	NA	3	With regular maintenance, no known limit	0.435

Table 3: Stirling Engine Technology Comparisons (Part 4 of 6)

Technology Type	Current Status		
	Criteria Emissions[1]	Toxic Emissions	Solid Wastes
Stirling engine Natural Gas	NOX – 1.0 CO – 6.0	None	NA
Stirling engine Bio- Gas	NOX – 1.5 CO – 1.9	None	NA

Notes: [1] Report residual air emissions, after installation and operation of all expected pollution control equipment, for the following (expressed in lbs./MWh)

Table 3: Stirling Engine Technology Comparisons (Part 5 of 6)

Technology Type	Projected 2010				Projected 2024			
	Installed Cost ($/kW)	Electrical Efficiency (%, LHV)	Availability (%)	Levelized Cost ($/kWh)	Installed Cost ($/kW)	Electrical Efficiency (%, LHV)	Availability (%)	Levelized Cost ($/kWh)
Stirling engine Natural Gas	$1000/kW	35%	97%	-	$900/kW	45%	98%	-
Stirling engine Bio- Gas	$1000/kW	35%	97%	-	$900/kW	45%	98%	-

Table 3: Stirling Engine Technology Comparisons (Part 6 of 6)

Technology Type/Application	Technology & Market Challenges	Commercial Status / # of Units Deployed	Leading Manufacturers	Manufacturing Locations	Other Comments
Stirling engine Natural Gas – can be used in any area where natural gas is present; rural or urban, if spark spread is agreeable.	**Technology Challenges:** - high cost needed for optimizing fuel economy via heat exchange efficiency. - dissipation of waste heat requires large radiators so difficult to compactly package - cannot start instantly; needs to "warm up" and best used as constant run, constant speed engines. - power output is constant and hard to change rapidly - if using Hydrogen as working fluid adds weight (for storage system), increase costs, and introduce some undesirable complications. Some engines use air as the working fluid which is less thermodynamically efficient but avoids loss problems. **Market Challenges:** - spark spread (i.e. cost of natural gas relative to cost of grid electricity). - market acceptance of new product.	- STM – 20-30 units total - Whisper Gen and Sunpower - Stirling Energy Systems – 500 - MW “SolarOne” project with Southern California Edison will be completed by 2009.	- STM Power Whisper Gen - Sunpower Stirling Energy Systems	Ann Arbor, MI New Zealand United Kingdom Athens, OH	Reflects ONLY data from STM Power
Stirling engine Bio- Gas					

Table 4: Battery Storage Technology Comparisons

Lithium Ion and Lithium Polymer Batteries: Lithium batteries (Li) are near maintenance free, have high cycle capability, do not generate hydrogen under normal operating conditions, and are half the weight and size of sealed lead acid batteries. Smaller versions of Li batteries are used in cell phones and laptop computers. Lithium is unstable in air and in many designs this may pose a risk .Currently the service life is about ½ to ¼ of Nickel Metal Hydride. The high cost, lower service life, and safety issues have limited the commercial use of Lithium in larger applications such as uninterrupted power systems (UPS) and Hybrid vehicles.

Nickel Cadmium Batteries (NiCad): NiCad batteries today come in both vented and sealed versions as well as a variety of plate materials and designs. Though NiCad batteries have been widely used, they are more expensive than Lead Acid batteries. NiCad's batteries cycle better than lead acid, withstand higher temperatures, have a higher energy density, are more predictable, and are more reliable than lead acid batteries. NiCad batteries, however, create environmental issues because the batteries contain cadmium. OHSA labels cadmium as "extremely toxic". Fire in a NiCad battery room can be life threatening because of the possibility of inhaled gases. NiCad batteries also have a memory effect that may be a major problem in UPS applications.

Nickel Metal Hydride Batteries (NiMH): NiMH batteries have been in hybrid vehicles for several years. As with Li Ion, NiCad, and other high end technologies, NiMH technology is more expensive than lead acid batteries. NiMH is attractive relative to lead acid batteries because of its superior cycling capability, better ambient temperature performance, safety, weight, and a smaller footprint. NiMH also out performs lead acid in comparable environment, life testing outcomes. Because of its chemistry, NiMH cell failure is much more predicable than lead acid cell failures. NiMH cells are projected to function for ten years or more and failure is normally indicated by a long warning impedance rise; reliability may equal or exceed that of flooded batteries in many applications.
NiMH can electrically discharge at full power to well below half nominal voltage without impacting service life, which allows for a smaller battery when associated with a generator. The battery is non-spillable, and does not have an explosive risk like that associated with lead acid or lithium. NiMH can reduce weight and footprint up to 75 percent when compared to sealed lead acid batteries. Because of their recycling ability, NiMH batteries are an excellent choice to pair with renewable generation applications. When cycled in parallel with a generator, battery can discharge well over 2000 times.

Lead Acid (LA): Lead Acid batteries can be found in a variety of formats. The most widely accepted and used types are high rate discharge rectangular plate "sealed" or "flooded" LA batteries. In both cases lead along with Calcium, Antimony or other alloys, make up the bulk of the plates. Concentrated Sulfuric Acid is the common electrolyte. The charge discharge process involves formation of explosive hydrogen. Air conditioning with these batteries is necessary since service life drops dramatically with rising temperatures. Sizing a lead acid battery to 25% more than the applications need is recommended due to heat related capacity loss.

Flooded Lead acid Batteries (FLA): Flooded batteries also known as vented or wet cell batteries, are usually the first choice for large data centers. These batteries are normally very reliable. They typically are sold with a pro rata warranty of 20 years. FLA batteries are subject to service affecting issues such as seal leaks, case cracks, plate growth, and other events which cause the loss of electrolyte. When loss of electrolyte occurs the results are immediate and catastrophic to the battery system as FLA batteries are usually in a single string configuration and offer no redundancy. Extensive maintenance is a necessity in FLA systems.

Sealed Lead Acid Batteries (SLA): Sealed lead acid, sometimes called recombinant, are readily available. Most common are gelled electrolyte and valve regulated with a design life of five years.

Typical useful life is three to five years. More expensive SLA is available with longer design life. SLA batteries are the product choice for small UPS, low bid, and non critical applications. Their first cost is so low that they significantly outsell FLA batteries. They are typically half the size and weight of FLA's. The largest problem with SLA's is dry out, which causes the loss of an entire string with the failure of one cell. It is also difficult to predict failure with this type of battery. Because of the high failure rate and lack of predictability SLA's should be installed in parallel to provide redundancy and to protect critical applications. Failure rates rise significantly in years four and five of typical SLA batteries. Although expensive, a program of monitoring the batteries should be considered to assure that the batteries' operating conditions are maintained and to help predict the batteries' useful service lives.

Ultracapacitors (UCs): Ultracapacitors (also called ultracaps, supercapacitors, or supercaps) have been an emerging technology for some time. Recently, however, they have become less expensive and field tests have been conducted in hybrid vehicles, rail systems and wind systems. As with many emerging technologies, UC's "first cost" is much higher than lead acid batteries. UC's have high cycling ability without impact to service life, but UC's are negatively affected, and their operating life can be shortened, as a result of exposure to high temperatures (> X°F or Y°C). Standard Warranty is only one year for most manufactures. Cell failure is typically projected at five to ten years; the failure mode is open circuit from electrolyte dry-out which, like SLA's, causes the loss of the entire string. For this reason, UC's are not normally considered for critical applications.

Source: http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2006-Spring/1013289_storage.pdf

CHAPTER 5C

Smart Power Grid – Alternative Technologies Workgroup

1. Introduction and Methodology

1.1 Introduction

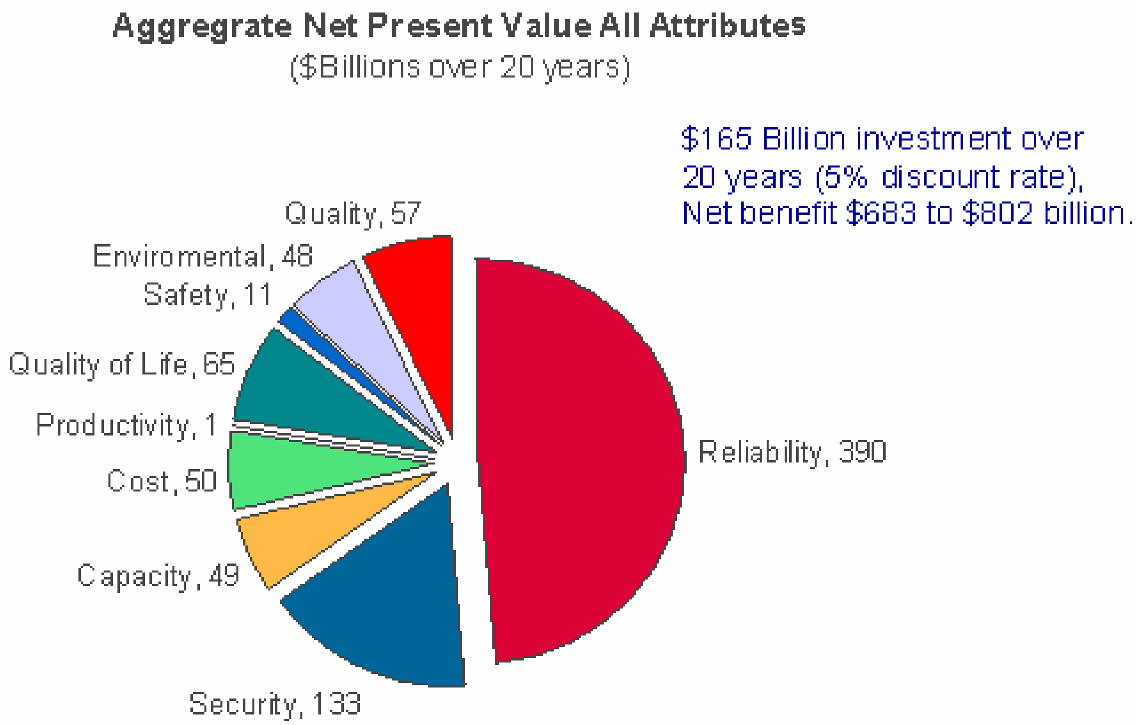
Market forces, technology advances, national energy policy and regulation are transforming the various components of the nation’s electric infrastructure and the manner in which the power grid is operated. For example, new regional markets are developing along with wholesale competition, and additional operational issues are surfacing along with the deployment of distributed generation resources and other new technologies. These changes have drawn attention to the opportunities for improved grid reliability, increased market efficiencies, and enhanced customer value, which these technologies can help realize.

Changes induced by new technologies are gradually beginning to transform the historical power grid system, which has been operated by electro-mechanical controls. The “Smart Power Grid” (SPG) is a general concept for this process of transforming the nation's electric power grid by applying computers, electronics, and advanced materials to implement communications, automated controls, and other forms of information technology to improve the economics, reliability and safety of the grid. This vision of a smart power grid integrates energy infrastructure, processes, devices, information, and markets into a coordinated and collaborative process which will allow electricity to be generated, distributed, and consumed more effectively and efficiently.

Eventually, implementation of smart power grid architecture will enable devices at all levels within the grid (from power generator to customer) to independently sense, anticipate and respond to real-time conditions by accessing, sharing and acting on real-time information. While the grid is gradually being transformed to provide these features, the challenge for all stakeholders is to maintain the reliability, security, and affordability of our power supply. The Figure 1 shows an estimate of the aggregate net present value of all smart power grid attributes, with the value of reliability and security accounting for 65 percent of the total value.

Figure 1: Smart Power Grid Estimated Value[82]

Value of Reliability and Security are Highest at 65 percent of Total



Planning, managing, and operating the electric power system in a coordinated and collaborative way can provide many benefits for both customers and power system providers. As new technologies become available, they can be integrated into the system when they can be shown to provide clear benefits. Smart power grid technologies continue to evolve and are in many different stages of development and commercialization. Incremental deployments of the new technologies will happen as their cost effectiveness is demonstrated and industry standards emerge. Many stakeholder groups are currently involved in the process of organizing, studying, specifying, designing, testing and implementing the hardware and concepts of a Smart Power Grid through a variety of study groups, alliances, collaborative, and pilot projects.

Additional information on technology options, barriers to adoption, commercial readiness, and applications related to smart power grid architecture and communications is presented later in this report, in Table 1 (p. 215)

[82] Source: *Power Delivery Systems of the Future: A Preliminary Estimate of Costs and Benefits*, EPRI, Palo Alto, CA: 2004; http://www.epri.com.

The Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability has identified seven principal characteristics of a smart electric grid.[83] These characteristics are:

1. Self-Healing: A grid able to rapidly detect, analyze, respond, and restore from perturbations.
2. Empower and Incorporate the Consumer: A grid able to incorporate consumer equipment and behavior.
3. Tolerant of a Security Attack: A grid that mitigates and stands resilient to physical and cyber security attack.
4. Provides Power Quality Needed by 21st Century Users: A grid that provides a quality of power consistent with consumer and industry needs.
5. Accommodates a Wide Variety of Generation Options: A grid that allows and takes advantage of a wide variety of local and regional generation technologies (including green power).
6. Fully Enables Electricity Markets: A grid that fully enables maturing electricity markets.
7. Optimizes Asset Utilization: A grid that employs IT and monitoring technologies to continually optimize its capital assets while minimizing operations and maintenance costs (O&M) costs.

1.2 Methodology

Workgroup participants identified four functional categories for smart grid technologies. These categories are:

1. architecture and communication standards;
2. monitoring and load management;
3. advanced grid operations; and
4. modeling and simulation.

These categories are intended to embrace the entire power system from points of energy production to points of energy use and the safe, reliable and efficient integration of both supply and demand.

The Smart Power Grid concept envisions even greater levels of functional integration with the application of increasingly sophisticated technologies for monitoring, operations, and control of the grid. The connection of many smaller generation sources and the requirements of higher power quality standards to power digital technologies are driving the need for new and more sophisticated grid operating technologies. Maintaining and improving historical levels of reliability, safety and economic efficiency will require an increased level of attention if the advancement of Smart Power Grid concepts is to make steady progress.

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[83]For more information, refer to the discussion beginning in Section 3.3 of this document and the following website: https://www.themoderngrid.org.

2. Smart Power Grid Architecture, Monitoring and Operations

2.1 Architecture and Communication Standards

Deployment of Smart Power Grid technologies will require increased emphasis on architecture and communications standards, which accommodate the many new operational requirements brought on by a transitioning electric power industry. Traditional levels of affordability, reliability, security and resilience must be supported and enhanced as the grid experiences new challenges. Some of these challenges include jurisdictional issues, increased power transactions between new market participants, increased need for new construction to relieve congestion, increased need for higher levels of power quality, greater need for grid security and the demand for more customer options.

The Smart Power Grid will require a new architecture which defines participants, grid functions and a systems approach to the interdependence of all of the grid's components. In this context, architecture describes the overall technical framework for development, installation, operation and maintenance of an information system. The Smart Power Grid is comprehensive reference architecture for the entire energy delivery infrastructure. Components of the architecture include the following:

1. develop approach for integrating legacy systems into a smart electricity infrastructure information system;
2. expand North American Electric Reliability Corporation (NERC) Electric Reliability Organization (ERO) approach to standard development;
3. construct an interoperability classification system;
4. define standards to satisfy operational requirements for domains within operational classification system; and
5. create the necessary security assessment tools.

The important challenges for identifying, scoping, specifying and implementing the Smart Power Grid architecture and standards requirements will include incorporation of large numbers of legacy systems for full functioning without degrading performance and reliability. In addition, many disparate industry and standards activities must be coordinated and compatible with operational technologies and capable of responding to day-to-day and emergency situations.

2.2 Monitoring and Load Management

The challenge for monitoring and load management technologies is to enhance monitoring of grid operations for power quality and power flow disturbance location, prediction and prevention. Also, improved monitoring and load management technologies should be employed to manage control of industrial, commercial and residential loads as part of demand side management (DSM) programs.

For purposes of grid monitoring and control, most electric utilities employ a Supervisory Control and Data Acquisition (SCADA) computer. The SCADA system is a communication tool enabling real-time measurements to be sent from substations to a System Control Center and control signals to be sent from the System Control Center to the substations. This system allows operators to monitor power flow through and voltage at high voltage substations and electric lines. It also allows operators to control certain electric facilities like circuit breakers by opening or closing circuit breakers remotely from the System Control Center.

Many SCADA systems have complementary or supplemental computer software packages for use by grid operators. This software allows grid operators to anticipate operational situations such as an increase in electric demand or the failure of a high voltage electric facility like a line or transformer. These supplemental computer software programs are often called advanced applications. One such application is termed "State Estimation." This software can use the real time SCADA information to predict power flow and voltage at certain locations on the power grid even though no telemetry information is available from the field. Another application is an on-line power flow. For example, using real time (on-line) SCADA information, operators and engineers can run simulations of hypothetical situations to better understand what operating issues may occur and devise a plan to manage an undesirable power flow situations.

Challenges for the future of monitoring and load management technologies include:

1. increased use of next-generation sensors on transmission and distribution equipment for accurate voltage, current and temperature measurements;
2. increased integration of grid system monitoring (SCADA) with customer usage monitoring (AMI) for purposes of improved power flow, power quality and diagnostics as well as enhanced customer service; and
3. increased development and use of smart appliance technologies.

For additional information on technology options, barriers to adoption, commercial readiness, and grid applications related to monitoring and control, see Table 1.

2.3 Grid Operations

Grid operations employ increasingly sophisticated components to balance power supply and demand. While distributed generation has not yet reached significant penetration levels in the U.S., the situation is changing rapidly, with national attention focused on alternatives to building traditional central station plants. Increasing the penetration levels for distributed generation will require specific attention to operational details required to maintain the transmission grid's integrity. This approach views individual distributed generators and their associated loads as a subsystem or "microgrid." The microgrid concept employs some of the following techniques:

1. increased efficiencies by matching generators and loads using waste heat sources;
2. intentional "islanding" during grid disturbances for improved reliability; and
3. sophisticated generator-based controls capable of smart-disconnect and resynchronization, thus avoiding complex customized control system engineering for each application.

Power quality improvement devices (i.e., uninterruptible power supplies, harmonic filters, and a combination of capacitors and inductors installed on customer equipment) are available on the market to help customers "ride through" customer and utility electric system disturbances. For example, Bay City Power Train, a General Motors manufacturing complex in Bay City, Michigan, has installed a Dynamic Voltage Restorer to help the plant operate through voltage sags or disturbances that may occur on the electric service to the plant.

Relay technology has dramatically changed in recent years to the digital age. As a result, much more detailed electric system monitoring information is now available via digital relays that are increasingly being installed throughout utility electric systems. As a result, fault locations (the location where a problem on the electric system has occurred – like a tree falling into a line) can be successfully determined by operators and engineers to aid in the deployment of field personnel to a location very close to the problem area. Without the ability to determine the location of the fault (or short circuit) on a line, field personnel have to inspect the line (sometimes walking it from one end to the other) to find the problem.

Communications technology has been improving and costs are declining. As a result, more options on economic terms are now available to automatically sectionalize distribution circuits. Consumers Energy has deployed S&C Electric's IntelliTeam switches and controls at a few locations on its low voltage distribution system. Such equipment will automatically reconfigure the low voltage distribution system during a failure and restore customers to service on parts of the distribution circuit not directly affected by the equipment failure.

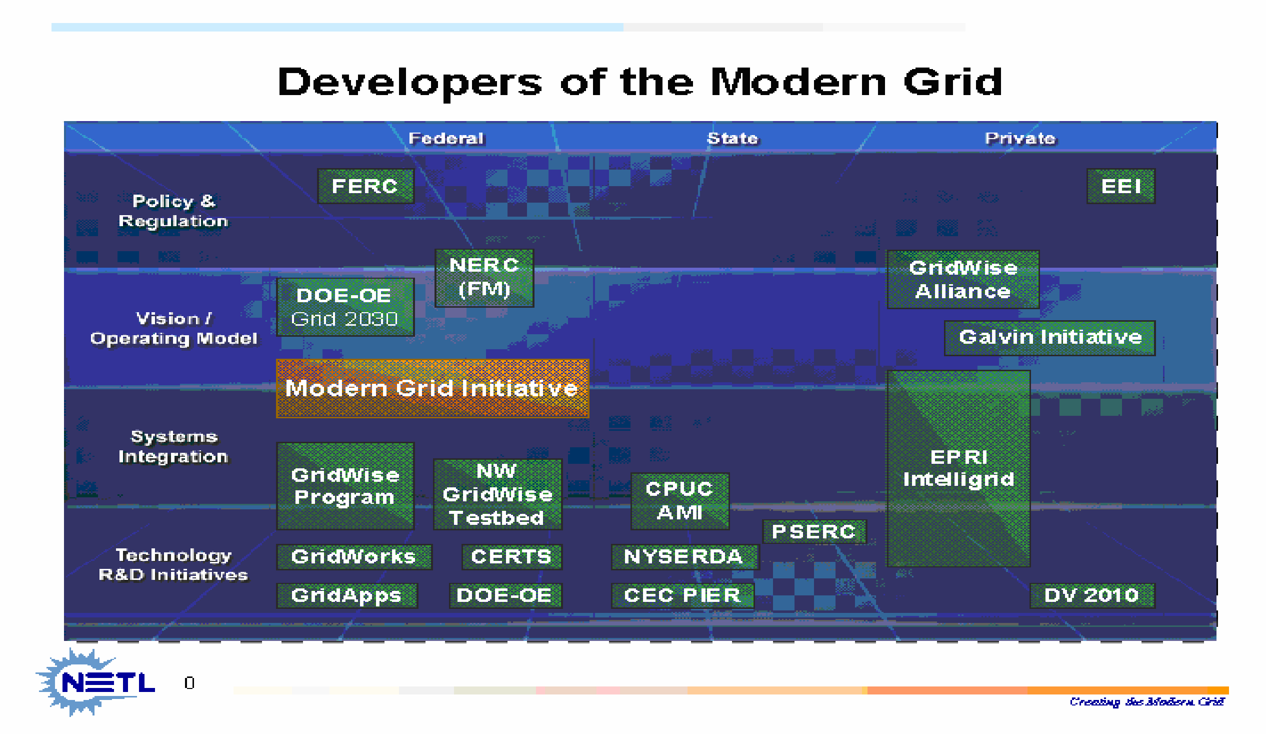
For additional information on technology options, barriers to adoption, commercial readiness, and grid applications related to advanced grid operations, see Table 1.

3. National Smart Power Grid Initiatives

There are several initiatives underway to explore the opportunities, performance, and operational issues of "smart grid" technology. Stakeholders involved in initiatives to transition the electric power grid infrastructure include approximately 3,000 electric utilities nationwide, their representative organizations, various trade and professional organizations that represent their employees, the Department of Energy, the Federal Energy Regulatory Commission (FERC), Congress, and the state public utility commissions, consumer protection and interest groups, and electricity consumers. Figure 2, provided by the National Energy Technology Laboratory (NETL)[84] depicts the development of the modern grid.

[84] NETL is part of DOE's national laboratory system and is owned and operated by the US Department of Energy. NETL is managing The Modern Grid Initiative that is discussed in more detail in Section 3.3 of this document. For more information on NETL, see link: http://www.netl.doe.gov/.

Figure 2: Developers of the Modern Grid - NETL



The nation-wide activities which complement federal energy policy can be loosely grouped as follows:

1. U.S. Department of Energy activities (GridWorks/Gridwise; Modern Grid Initiative; etc.);
2. university consortium activities (PSERC);
3. industry supported projects (EPRI's Intelligrid Consortium);
4. privately-funded activities (Galvin Initiative); and
5. state programs.

A description of each initiative is included below.

3.1 IntelliGrid[85] (EPRI)

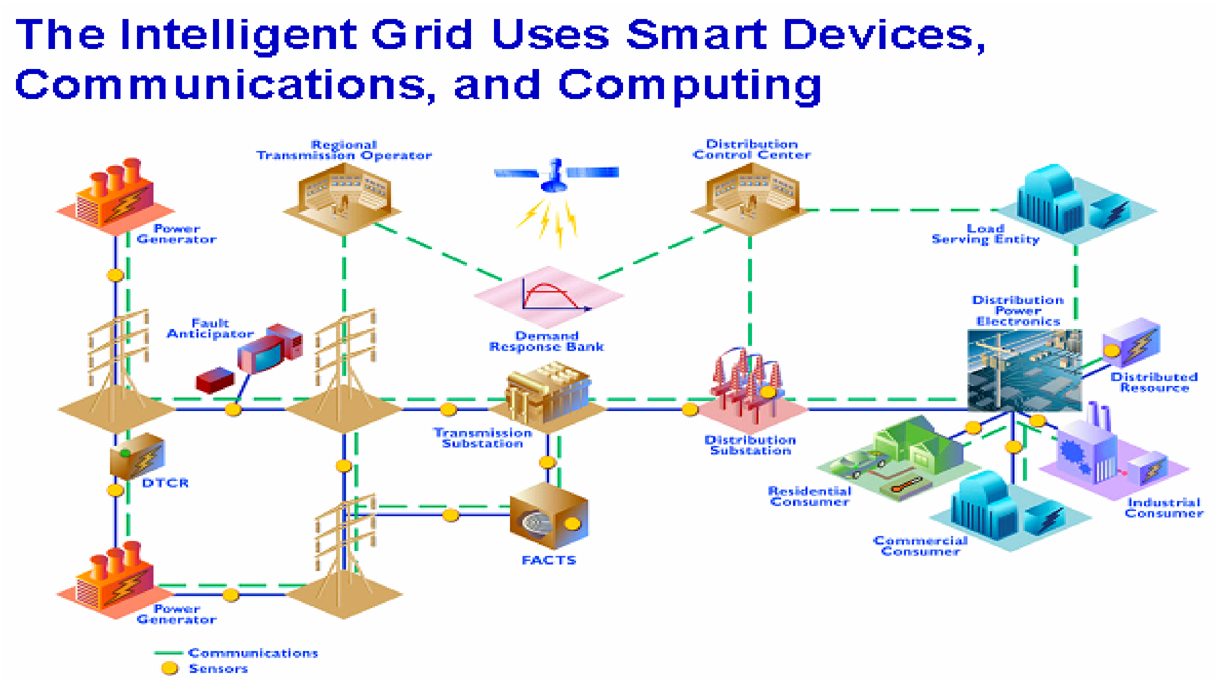
The IntelliGrid Consortium was created by the Electric Power Research Institute (EPRI) to help the industry pave the way to the Intelligrid vision of the power grid of the future. Such an evolution means avoiding easy short-term solutions that lead to a "silo" approach - one without regard to the needs of other parts of the grid. It stresses the advantage and need for open

[85]Source: Abstracted from the EPRI IntelliGrid website with permission of EPRI see: http://www.epri.com/IntelliGrid/ for further information.

standards, coordination of research and development (R&D), collaboration among all stakeholders and a leadership role in the industry standards boards and regulatory bodies. The process is the key to the success of IntelliGrid. Success requires adoption by the industry. Figure 3 illustrates the Intelligrid vision.

The IntelliGrid Consortium is a public/private partnership that integrates and optimizes global research efforts, funds high-impact R&D on enabling technologies and on the integration of technologies to achieve the vision of the power delivery system of the future. The IntelliGrid Consortium also leads an international effort to disseminate technical conclusions for the benefit of the public by promoting its adoption by others (standard groups, trade associations, etc.).

Figure 3: EPRI Intelligent Grid Communications



The IntelliGrid Architecture is a world-wide and industry-wide project to develop the infrastructures necessary to support the next generation of energy conversion, delivery and end-use systems. The IntelliGrid Architecture builds upon work within several developing and emerging open standards to enable not only interoperable equipment but provide a framework for the development of the next generation of automation applications. The Architecture focuses on the effective integration of two infrastructures:

- electric energy and power delivery system; and
- communications and intelligent equipment that will be used to control and manage energy and power systems in the future.

The IntelliGrid Architecture development began with an initial project known as the Integrated Energy and Communications System Architecture (IECSA). This project provided an initial set of requirements that represent "architecturally significant" applications, analyses and guidelines to help direct the industry toward the development of advanced automation systems that can be integrated on large scales.

The IntelliGrid Architecture is focused on the effective use of advanced automation products that can be integrated through the use of open standards, many of which are now or have reached maturity. Architecture development is necessary to manage the complexity of future applications and technologies, and to assist the development of advanced devices and systems that are interoperable.

The scope of IntelliGrid Architecture is as large as the existing energy conversion, delivery and end-use technologies. This broad scope is necessary to encompass the levels of integration that by definition constitute industry-level architecture. For context with existing power system taxonomy, the team initially categorized the work by traditional technical domains as follows:

- central power generation;
- transmission operations;
- market operations;
- distribution operations;
- distributed energy resources;
- consumer communications; and
- federated and system management services.

Other major IntelliGrid project areas include the following:

3.1.1 Fast Simulation and Modeling

Fast Simulation and Modeling intended to help the operators to have a clear and accurate estimation of the grid, to cost efficiently optimize the operations, and anticipate responses to events in real time, achieve faster-than-real time simulation and modeling of electricity grid dynamics over a range of different geographic and time domains.

3.1.2 The Consumer Portal

The Consumer Portal intended to enable consumers to participate in the competitive energy markets, and provide action and feedback from the consumers, who represent millions of connecting points to the network. It not only provides an interface for energy related services (e.g., meter reading, outage detection, demand response, bill disaggregation, and real-time pricing), but also numerous additional potential functions to industrial, commercial, and residential electric energy users**.**

Communication Standards for Distributed Energy Resource (DER) Integration and for Advanced Distributed Automation (ADA) – Changes to the distribution electrical system and communication system are needed in order to fully capture the prospective benefits of new distribution technologies. Individual equipment types, such as DER, must be made interoperable with overall infrastructure. This project addresses communication standards aimed at helping to achieve this interoperability.

3.2 GridWorks/GridWise[86] (DOE)

There are two U.S. Department of Energy directed research and development programs (GridWorks and GridWise) to improve the reliability of the electric infrastructure through research and development of key grid systems and components.

The GridWorks program addresses introduction of “next generation” grid hardware. Participants include electric utilities, equipment manufacturers, state government agencies, National Laboratories and universities. The GridWorks effort began in October 2004 and has been conducted on a workshop format. The workshop effort was designed to encourage partnerships and collaboration to achieve implementation of advanced grid hardware in three major areas. These areas are: (1) cables and conductors; (2) power electronics; and (3) substation and protective equipment. The workshops concluded with production of a GridWorks Multi-Year Plan in March 2005.

The GridWise program addresses increased integration of information systems and digital technologies into the electric grid. The future electric system is expected to employ new distributed "plug and play" technologies using advanced telecommunications, information and control approaches to create a society of devices that functions as an integrated transactive system.

The GridWise Alliance is a consortium of public and private stakeholders who have joined together in a collaborative effort to provide practical technology solutions to support the U.S. Department of Energy's vision of a transformed national electric system.

3.3 Modern Grid Initiative[87] from DOE

The Modern Grid Initiative (MGI) was commenced in April of 2005, when the DOE Office of Electricity Delivery and Energy Reliability asked the National Energy Technology Laboratory to create the Modern Grid Initiative to advance a national effort involving a partnership among utilities, consumers, national labs, academia, industry firms, regulators and policy makers to improve the national grid in a way to support the 21st century U.S. economy. The MGI is intended to empower researchers and other stakeholders to connect, collaborate and move forward in partnership through summits, working groups, and developmental field tests.

MGI has started the process of hosting a series of regional summits in the U.S. in order to engage a broad range of stakeholders in creating a shared national agenda for modernizing the electrical grid. To date, MGI has hosted a Southwest Regional Summit in Arizona (November 2005 with 60 attendees), a Northwest Regional Summit in Oregon (April 2006 with 80 attendees), a Northeast Regional Summit in Maine (June 2006), and a Southeast Regional Summit in

[86] For more information, about DOE GridWise, see web link at: http://gridwise.pnl.gov/. For more information about DOE GridWorks, see web link at: http://www.oe.energy.gov/randd/gridworks.htm.

[87] For more information about the Modern Grid Initiative, see web link at http://www.themoderngrid.org/.

Tennessee (August 2006), a San Diego Summit (October 2006), and a Midwest Regional Summit in Ohio (November 2006). Upon completion of the Regional Summits, MGI plans to host a National Summit in order to share the information gained from the Regional Summits, and obtain feedback from a large audience of stakeholders. In addition to the summits, MGI established a working group in July 2006 in order to improve the quality of MGI concepts, create consensus for MGI concepts, increase the credibility of MGI concepts, and provide stakeholders another opportunity to participate.

In April 2006, MGI reached an agreement in principal with American Electric Power (AEP) for a developmental field test of advanced grid technologies in West Virginia, delivering some of the principal characteristics of the Modern Grid. In May 2006, MGI reached an agreement in principal with Allegheny Power for a similar developmental field test in West Virginia.

MGI's goals for fiscal year 2007 include the full operation of two to three developmental field tests, and continued stakeholder alignment. The goals for fiscal years 2008 through 2012 include the bid, selection and deployment of large regional demonstration projects, as well as the refinement of the Modern Grid strategies through lessons from the demonstrations. MGI expects that the adoption of the Modern Grid strategies by appropriate national and state organizations will take place in 2013, which will be the basis for national deployment.

3.4 GridApp™[88]

GridApp™ (Advanced Grid Applications Consortium), a partnership of electrical utilities and the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability. The mission of GridApp™ is to transition best technologies and best practices to support grid modernization into broad use by consortium member utilities.

This multi-company consortium focuses on High-Impact Technologies for electricity distribution and transmission, including: sensors, communications, information technologies, power electronics, smart systems, and system integration. GridApp™ provides a fast track for engineering development, demonstration, verification, and validation of selected, High-Impact Technologies and practices. GridApp™ also provides informational briefings and technology showcases to promote use by all member utilities. GridApp™ is designed in a flexible way to allow for rapid deployment of innovations and activities that focus on development of technologies with a high potential for near-term application and commercialization. GridApp™ provides member utilities with technical and financial resources to develop and deploy grid modernization technologies that they would be unable to develop and deploy on their own. Participants in GridApp™ benefit from:

1. pooling resources to fund best technologies/practices;
2. bringing commercially available technologies into real use;
3. lowering market entry barriers for new technologies;
4. gaining advance knowledge of and preferred pricing on GridApp™ technologies in Core and Strategic projects;

[88] For more information about GridApp™, see web link at https://www.gridapp.org/eidb/gridapp_home.htm.

5. partaking in a forum to communicate and share technology advancements;
6. becoming an effective change agent of new technologies important to the utility industry; and
7. forging a collective voice of the utility industry for advocacy of technology investments.

Coordinating collaborative approaches with federal/state programs to support high-priority projects, the GridApp™ mission is dedicated to transitioning utility "best practices and technologies" into broad use by GridApp™ Consortium member utilities. The GridApp™ focus is on high-impact technologies for distribution and transmission operations, including but not limited to; sensors, controls, communications, power electronics, smart systems and system integration.

GridApp™ intends to fast-track the engineering development, demonstration, verification, validation and deployment of such high-impact technologies and practices with beta-testing completed in less than 18 months. In addition GridApp™ provides a venue for informational briefings, technology showcase and networking opportunities for participating Consortium members.

3.5 Galvin Electricity Initiative[89]

On September 22, 2005, the Galvin Electricity Initiative officially announced its mission to create a blueprint for transforming the U.S. electricity supply and service infrastructure into a resilient and adaptable system supporting the needs of the rapidly evolving digital economy. The fundamental principle of this Initiative is that raising the quality of the nation's electricity supply system will create substantial cost savings for all consumers and society at large.

The Initiative is a privately funded enterprise sponsored by the Galvin Project, Inc., which is led by Bob Galvin, former CEO of Motorola and a key figure in establishing the internationally recognized "Six Sigma" quality control process. According to EPRI President Emeritus Kurt Yeager, who is leading the Galvin Electricity Initiative, "The electric infrastructure has to be transformed. It was adequate for the analog, electromechanical world of the 20th century, but needs to be reinvented to meet the demands of the '24-7' electronic age."

The Galvin Project consists of two phases and is being conducted by researchers from EPRI, under the leadership of Clark W. Gellings, Vice President of Innovation, with support from EPRI Solutions, Inc., Strategic Decisions Group, and the University of Minnesota. The goal of the, recently completed, first phase was to determine the principal innovations which will play A major role in adapting to and shaping customers' electric energy service needs in the next 10 to 20 years.

[89] For more information, see web link at http://www.galvinelectricity.org/.

3.6 MultiSpeak® Initiative (NRECA)[90]

The MultiSpeak® Initiative is a collaborative effort of the National Rural Electric Cooperative Association (NRECA) and more than 30 software providers and consultants serving electric utilities. The MultiSpeak® collaborative effort began around October 1999 and offers independent specifications that are used by software developers to simplify business process improvement and data integration at electric utilities, with particular emphasis on electric distribution cooperatives. The MultiSpeak® specification defines what data is exchanged among commonly used software applications, and establishes standardized messaging formats. Software providers use the specification to write interfaces that will enable the interchange of information with other software that supports MultiSpeak®.

MultiSpeak®3, the latest release of the specification, supports batch file transfers and real-time transport using web services, which standardize the transport of instructions and data among MultiSpeak®-compatible software applications. MultiSpeak®3 defines more than 200 unique web service methods to implement real-time data and process integration. In addition to automated meter reading and engineering analysis, software applications covered in the latest specification include customer information systems, outage detection, outage management systems, field design software, geographic information systems, customer relationship management, load management, and SCADA.

3.7 Consortium for Electric Reliability Technology Solutions[91]

The Consortium for Electric Reliability Technology Solutions (CERTS) is an organization formed in 1999 to research, develop, and disseminate new methods, tools, and technologies to support electric power system reliability and the functioning of competitive electricity markets in the United States. CERTS includes participants from universities, national laboratories and private industry. CERTS are currently conducting research for the U.S. Department of Energy Transmission Reliability Program and for the California Energy Commission (CEC) Public Interest Energy Research (PIER) Program. The members of CERTS include the Electric Power Group, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, the National Science Foundation's Power Systems Engineering Research Center, and Sandia National Laboratories.

The CERTS Microgrid concept, a major focus of the consortium, employs distributed energy resources (DER) to improve grid reliability and efficiency. A high-speed switch with appropriate sensing capability is used to isolate the microgrid from the power system during abnormal grid conditions. This approach improves local power quality and diminishes the chances of a local disturbance propagating a wider grid disruption.

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[90] For more information, see web link at http://www.multispeak.org/.

[91] For more information, see web link at http://certs.lbl.gov/.

3.8 Distribution Vision 2010 Consortium

The Distribution Vision 2010 Limited Liability Company was formed July 2002, with five registered owners: Wisconsin Energy Corp., Alliant Energy, AEP, PSE&G, and OG&E. BC Hydro is a non-owning member of the consortium. DV2010 was organized to develop ideas for new technologies for the power distribution industry. The goal of the consortium is to improve the reliability of customer service. The approach is to develop conceptual ideas for new technologies and fund the engineering feasibility studies necessary for commercialization of those ideas. It seeks out industrial suppliers with the best potential for bringing the best ideas to market.

4. Michigan Grid Modernization Technologies

4.1 Introduction

The Michigan electric industry has already made significant investments in communication and information handling infrastructure and the associated equipment and components.

For example, most modern control areas use a Supervisory Control and Data Acquisition (SCADA) system for real time information and control. SCADA systems can also be used to more efficiently and more optimally operate electric devices on the system, like switchable capacitor banks. Consumers Energy has implemented a program which allow certain capacitor banks located on low voltage distribution circuit feeders to be switched on and off by the reactive power flow on the high voltage electric line feeding the low voltage distribution line. This in turn results in reduced use of devices like voltage regulators (allowing decreased equipment wear and tear and lower maintenance costs) and achieves a flatter voltage profile on distribution circuits. It also reduces electric system losses and enhances the availability of reactive power.

As another example, some utilities employ power quality recording devices at large customer locations to monitor service at the power of interconnection between a customer and utility. These devices help identify power disruption events on the utility system or the customer's system when the customer experiences a disruption, and they can also help predict the imminent failure or poor operation of an electrical device before failure of the device occurs.

A number of Michigan cooperative electric distribution companies have already initiated programs to replace utility meters that required manual meter reads with new ones that allow automatic meter reading. Such technologies permit two-way communications between the customer meter and the distribution company's control center. Not only can meters be read remotely, outage assessments can likewise be performed without dispatching crews or awaiting calls from customers reporting outages. Detroit Edison (DTE) has experimented with meter communications over both its distribution system and via fiber-optic cable.

State policy has also pushed the need for grid modernization. The Commission has adopted interconnection standards for units interconnecting to the distribution system in Michigan. These standards are intended to provide uniform requirements for distributed energy resources that seek to interconnect to Michigan's power grid. The Commission has also adopted a net metering program for small, renewable applications. Under this program, units that produce less than 30 kilowatts (kW) from a renewable power source can produce electricity for domestic use and receive credit for any excess generation delivered to the power grid.

4.2 Grid Modernization Recommendations

If grid modernization is approached in a thoughtful manner, Michigan can become the center for electricity innovation, which will attract investment, and encourage successful businesses to locate here. Advancing the concept of the Smart Power Grid will provide a more reliable and secure power supply, provide other directed economic benefits, and stimulate technological innovation and bring about a more vibrant economy and a better quality of life for Michigan residents.

4.3 Collaborative Concept for Michigan

A collaboration-focused approach allows participants an opportunity to achieve mutual success by leveraging technology and innovative ideas to advance the concept of a Smart Power Grid. The many successful national collaborative efforts investigating advanced grid technologies will provide guidance to similar efforts for Michigan.

4.4 Pilot Project Concept for Utility(s)

A number of pilot projects are underway around the country. A federal energy policy push is encouraging media coverage as well as deployment of pilot programs to advance Smart Power Grid technologies. Consumers Energy currently has a pilot program for Broadband over Powerline (BPL) underway in Michigan. There a number of BPL deployments around the country. Several have gone beyond the pilot stage. Other Smart Power Grid and related applications are also being deployed in pilot projects. Examples include smart appliances, smart metering, power outage monitoring, monitoring of grid component failures and others.

The Energy Policy Act of 2005 (EPACT 2005) directs the FERC to encourage the deployment of advanced transmission technologies and authorizes the Secretary of Energy to establish an Advanced Power System Technology Incentive Program to deploy certain advanced power system technologies. Also, EPACT 2005 amends the Public Utility Regulatory Policies Act of 1978 (PURPA) by encouraging each state regulatory authority to investigate the use of time-based meters and communication devices. The current legislative environment should stimulate interest in beginning pilots in these technology areas.

4.5 Detroit Edison Modernization Activities

The following DTE initiatives support smart power grid technical categories and involve both full scale and pilot deployments.

4.5.1 Aggregation, Communication and Control of Distributed Energy Resources

As the project leader of a Department of Energy funded demonstration project, DTE created the communication and system architecture, and the procedures to monitor and control multiple DERs from numerous manufacturers connected to the electric distribution system. Procedures were created which protect the distribution network and personnel that may be working on the network. Using the web as the communication medium for control and monitoring of the DERs, the integration of information and security was accomplished through the use of industry standard protocols such as SSL (secure sockets layer) and ICCP (Inter control center protocol).

In Phase II of the project (completed in 2006), marketing procedures were developed for marketing the power of the aggregated DERs by commercial node in the Midwest Independent System Operator (MISO) energy market. DTE demonstrated the economic dispatch of 32 generators at 24 different sites, totaling 18 megawatts (MW) in response to market signals without human intervention. The selection of standards-based communication technologies offers the ability of the system to be deployed and integrated with other utilities' resources.

4.5.2 SCADA/EMS Replacement

DTE's existing SCADA and Energy Management System is being replaced due to obsolescence, the new system will enable DTE to meet the NERC Critical Infrastructure Protection (CIP) Standards. The applications included in the replacement are SCADA, Historian for data storage and retrieval, network applications such as State Estimator and Contingency Analysis that support real time analysis and operation planning, and Dispatcher Training Simulator. New tools with this replacement include real time distribution study tools, to facilitate restoration and loading of the distribution circuits.

The new system architecture will consist of an integrated Energy Management System and Distribution Management System. Some of the features include:

- sized to be able to grow the system by 50 percent and not affect performance.;
- CIM/XML Schema for model exchange;
- DNP 3.0 and DNP over IP protocols;
- ICCP and Secure ICCP for real time data exchange;
- User Interface that supports interoperability with MS Windows applications;
- web based displays for viewing;
- creation of a disaster recovery system;
- on-line study tools for System Operators to utilize to improve restoration; and
- distribution VAR control to utilize feeder capacitors efficiently.

System implementation began in the 4th quarter of 2004 and cutover is anticipated in the 3rd quarter of 2007.

4.5.3 GridApp™ Technologies

DTE is a member of GridApp™ and is the project leader for a single phase dropout recloser project that is to replace a standard utility fuse. Most faults on overhead distribution circuits are momentary outages causing fuses to blow to isolate faults resulting in customer outage until the utility replaces the fuse. A device that will operate to reduce the chance of a momentary faults becoming a permanent fault will translate into reduced momentary outages for customers, directly increasing customer satisfaction and reducing outage cost for utilities.

Another product DTE is using that was developed by a GridApp™ utility is a padmounted substation (also referred as a DC-IN-A-BOX). Because growth in existing electric infrastructure often requires new and expanded substations, a method was needed to accommodate substation siting using a less objectionable design, allowing for quicker installation, while lowering substation costs.

The Substation in a Box system offers a smaller footprint, is more aesthetically appealing while using underground cabling. The installation requires no fence topped with barbed wire for security and personal protection and no spill containment is required, thus security is enhanced. The system uses completely enclosed boxes with no exposed energized parts.

4.5.4 Automated Meter Reading

DTE has a long history of piloting new automated meter reading (AMR) technologies. As early as 1979, DTE tested AMR technology in partnership with the Electric Power Research Institute. The technology utilized at the time was a Westinghouse powerline carrier system that used existing utility lines for communication.

In 1988, a pilot involving 93 residential customer locations were automated in the Dearborn area. The meters were wired to “talk” to a central computer system over a Michigan Bell telephone line. Each meter location was retrofitted with a meter interface unit which allowed communication with up to four additional devices such as water and gas meters on the home. At the same time another pilot in the Troy area tested a system that read meters using a cable television connection. The cable system also collected meter readings from water meters at the same locations. In the late 1990s a custom technology pilot was designed in partnership with several technology vendors such as Echelon, Comcast Cable, and Hewlett Packard. This new two-way system was installed at 160 customer homes. The customers were provided an experimental time-of-use rate and the opportunity to control home appliances remotely. In 2002, a pilot of AMR fixed network technology was installed using an Itron 960 megahertz (MHz) and 1 gigahertz (GHz) meter reading system. The system was installed to cover 1,127 customer locations.

Several types of AMR technologies are currently used today at DTE. Approximately 130,000 hard to access meter locations are read via handheld radio technology. Each meter is retrofitted with a small Itron radio encoder device called an ERT module. The handheld devices used by meter readers contain a radio that picks up the meter reads when they are within a couple hundred feet of the meter. This eliminates the need for the meter reader to walk directly up to the meter in hazardous or hard to access locations. In addition, approximately 11,000 industrial, commercial, and Load Research customer locations with interval meters are read weekly over telephone lines. A mix of both wired phone lines and analog cellular phones are used to communicate with these meters.

Many other lab tests of emerging technologies have been evaluated by DTE over the years. While many are very promising and demonstrate a reliable and accurate means of collecting data they must be cost justified as a transformation technology benefiting all areas of the utility business. The Energy Policy Act in 2005 has significantly spurred the market for AMR technology innovation. The new innovation has also shown reduced cost and improved customer benefits, which helps the business case to move forward beyond the pilot stage.

Though a specific vendor has yet to be selected, DTE anticipates full service territory AMR deployment and installation over the next six years. The company plans to use a phased in approach and begin meter replacements in the areas with the highest density of meters.

4.5.5 Distributed Energy Resource Activities

DER can sometimes impact system planning, operations, and economics in ways not usually considered part of distribution planning or operations.

Presently, DTE is installing DG in the distribution system as a practical and economical solution to local reliability and power quality problems. Like a portable substation, DG can be used as an emergency, temporary, maintenance or permanent system. DTE reports that in its experience in using DG as a distribution planning tool, at most 3 percent of its circuits may have applications for DG. It serves as another tool that planning engineers can use to resolve loading problems.

These installations can help:

1. eliminate or defer expensive distribution system expansions;
2. improve distribution system reliability;
3. generate environmentally clean power and most importantly; and
4. provide high quality service to customers.

In 2003, DTE Energy Technologies, Inc signed a contract with NextEnergy to design and construct a state-of-the-art microgrid in the Power Pavilion on the NextEnergy site in Detroit. This microgrid demonstration project will be fueled by hydrogen, natural gas and sunlight. It will include the use of several emerging on-site energy technologies, including fuel cells, internal and external combustion engines, and solar cells. The microgrid will also include underground electrical and thermal distribution systems to provide electricity, heating and air conditioning to the NextEnergy facility. In addition, it will have the capability to serve the broader energy needs of the prospective buildings located within “Tech Town,” a research and business technology park under development on the campus of Wayne State University in Detroit. The NextEnergy facility includes a 5,600-square-foot Power Pavilion, which will house the microgrid, a hydrogen fueling infrastructure, office space, as well as a laboratory and product demonstration and exhibition facilities.

DTE is actively implementing DG in its distribution system to resolve both utility and customer problems. DTE has conducted DG technology demonstrations and installed DG as distribution solutions internal to the distribution circuit, at the substation and in an island mode to perform maintenance.

Throughout these implementations, DTE is:

1. partnering with customers on overloaded circuits, sharing the costs and benefits of DG through a premium power rate;
2. formally including DG analysis into the capital budget process as an alternative to traditional T&D solutions;
3. listing all known customer-owned DG and/or interruptible equipment; and
4. developing tools, such as the Distribution Engineering Workstation (DEW), to quantify the impacts of DG on the distribution system, particularly with regard to protection concerns.

DTE's operational strategy is to use DG to resolve distribution problems, not primarily as a generation option.

DTE has a fleet of seven DGs in use to support distribution ranging in size from 1 MW natural gas to 2 MW diesel fuel. They also have a 1.5 MW bi-fuel that can operate on blended natural gas and diesel. For 2006, six of the seven DG installations have been available to manage peak load.

In the longer term, DTE sees DG as a technology comparable to personal computers and cell phones. Just as these technologies fundamentally altered the computer and telecommunications industries, DG can help transform the traditional paradigm of the electric power system. DTE believes that DG will increasingly be a part of the utility landscape and play an expanding role in providing reliable, economical and high quality power.

Looking a bit further ahead, DTE envisions DER microgrids, or virtual utilities, providing continuous, economical, on-site power to multiple users and facilities in developments, complexes and premium power parks. The microgrid's appeal is:

1. fast siting;
2. comparatively low initial costs and high efficiency;
3. improved power quality, reliability and security; and
4. the capability of selling surplus energy.

4.6 Consumers Energy Modernization Activities

The following Consumers Energy initiatives support smart power grid technical categories and involve both full scale and pilot deployments.

4.6.1 SCADA/EMS Replacement

Consumers Energy is in the process of replacing its SCADA and Energy Management System which is driven by obsolescence, NERC Critical Infrastructure Protection (CIP) Standards, FERC Code of Conduct and the need for improved functionality.

The new system architecture will enable communication with multiple vendor applications and systems using industry accepted protocols. Some of the features include:

- CIM/XML Schema for model exchange;
- DNP 3.0 and DNP over IP protocols for communication with remote IEDs;
- ICCP and Secure ICCP for real time data;
- Multi Platform support Windows, Linux, and Unix;
- User Interface that supports interoperability with MS Windows applications;
- web based displays for viewing; and
- all databases, real time and historical, will be Open DataBase Compliant (ODBC).

System implementation is expected to begin in the 3rd quarter of 2006 and cutover is anticipated in the 2nd quarter of 2008.

4.6.2 Distribution Automation Intelligent Switching

Automatic load transfer switching schemes have been employed on utility distribution systems for some time. Recent advancements in wireless communication and smart switch capabilities have improved the functionality and expanded the potential application of smart “islands of automation.”

Consumers Energy has deployed four islands of automation on its low voltage distribution system using S&C’s IntelliTEAM technology. Each team involves two separate feeders and two to five intelligent switches, with one switch operated as the normal open point between the feeders. Using unlicensed spread-spectrum radio communication, the switches continually communicate with each other, monitoring the load and status of each switch. When a fault occurs on one of the feeders, all switches verify each others status and automatically restores all sections of the feeder up to the faulted section. The switches are also capable of determining the load serving capability of each section and will block transfer if the reconfigured system would result in an overload. This added intelligence results in automatic load transfer capabilities for all but a few days of the year where full redundancy does not exist between feeders.

One of the installed teams has been further enhanced by connecting the spread-spectrum communication into the SCADA system, making the real-time status and load information available anywhere in the company.

Investigation is underway with the latest generation of "islands of automation" technology that allows interconnection of up to eight substation and circuit combinations versus the present limit of only two feeders per team. The same features above apply with additional intelligence that allows more interruption scenarios and contingencies to be automatically restored. The new switches and controls also have the capability to change their internal settings so that system protection coordination can be maintained in the multiple system configurations.

4.6.3 Broadband Over Powerline

Commercial broadband over powerline has migrated from European to North American Markets over the past several years. Monitoring of trials, commercial deployments, regulatory issues and the potential for distribution applications, culminated in an agreement with The Shpigler Group to deploy a commercial pilot in the cities of Grand Ledge and St. Johns. Consumers Energy adopted the Landlord/Tenant business model used for other communication providers that attach to its system. The Shpigler Group owns and operates the BPL system and provides internet service under the name of Lighthouse Broadband.

BPL has the potential to enable distribution smart power grid applications by creating a communication network over the low voltage distribution system, providing connection to substations, critical line devices, customer meters and devices in the home. As part of the deployment, Consumers Energy intends a proof of concept pilot including substation equipment monitoring, distribution line equipment monitoring and meter reading.

Added grid intelligence is possible through the BPL Network Operating System that continually monitors the status of BPL field devices. Electric distribution outage and restoration status could potentially be inferred through monitoring BPL network/devices and making that information available to the utility to aid restoration activities. In cooperation with Lighthouse Broadband, the reliability and usefulness of outage information will be evaluated once the commercial roll out is significantly completed.

Lighthouse Broadband is testing new BPL technology and evaluating the performance. Initial tests were very positive and further production deployment is expected to commence once all testing and evaluations are completed. The determination to expand deployment beyond Grand Ledge and St. Johns will be once those systems are deployed and the distribution applications evaluated.

4.7 Indiana Michigan Power AMR

Indiana Michigan Power (I&M) employs AMR technology for about 30 percent of its meters in Michigan, primarily single phase residential services. Two AMR projects in Michigan were completed in 2005: (1) about 25,000 radio frequency (RF) meters are installed in the Benton

Harbor – St. Joseph – Stevensville area; and (2) approximately 14,000 power line carrier (PLC) meters are installed on nine circuits in other parts of the service territory. These are one way systems allowing the company to read meters.

The RF technology uses primarily General Electric meters with an Itron radio transmitting module. Meters are read using either hand held receivers or a laptop computer-driven receiver. The PLC system uses Hunt Technology meters and a receiver at the substation. These meters send data packets with a reading every 27 hours. Both systems can generate tamper and inversion detection flags.

In the next two years, I&M plans to install meters with three transmission modules in areas where the AMR technology is installed, to allow demand and time of use applications. I&M anticipates moving towards full deployment of AMR in the coming years.

Elsewhere on the AEP system, multiple automation pilot programs and investigations with outside suppliers are underway to determine the feasibility and future applications for smartgrid technology.

4.8 We Energies AMR

We Energies serves over 2.1 million customers in Wisconsin and the Upper Peninsula of Michigan, with over 1.1 million electric meters and one million gas meters. Deployment of AMR technology started with approximately 400,000 drive-by Itron modules on gas meters in Wisconsin beginning in 1992. AMR expansion began in 2002 using the Cellnet Technology, Inc., fixed network AMR system. AMR use has expanded to include over 650,000 gas and electric meters in the Wisconsin service areas and additional expansion is planned in coming years. Customer reaction to the AMR deployment has been very positive.

4.9 Great Lakes Energy Cooperative AMR (TWACS)[92]

Great Lakes Energy Cooperative (GLE) serves approximately 120,000 meters. GLE has a fully implemented AMR program consisting of about 120,000 Two-Way Automatic Communication System (TWACS) AMR meters by DCSI. The TWACS system is a two-way power line carrier system that delivers data in two directions over the utility's power lines. A pilot project that was started in late 2004 has been fully implemented since the second quarter of 2006.

GLE presently obtains daily meter reads for its entire system. The system has the capability to obtain hourly meters reads which could be used to obtain demand data for load profiling. The system can determine if a meter is energized and therefore can detect power outages and is integrated with GLE's Outage Management System. Customer voltage reads can be obtained from the system as well.

[92] For more information regarding the Two-Way Automatic Communication System (TWACS) system, go to http://www.twacs.com/index.html.

Remote disconnect/reconnect devices became available in 2006 and limited implementation was started in the second quarter 2006. Both the TWACS-DCSI AMR and the remote disconnect unit can detect metering tampering as well. MultiSpeak was used in the interface between GLE's Milsoft Outage Management system and the TWACS AMR system software.

4.10 Cloverland Cooperative AMR

Cloverland serves approximately 19,100 electric meters and began installing AMR technology in 2005. The co-op elected to proceed with full deployment of the DSCI (TWACS) fixed PLC system coupled with mixed communication components from the substations to the office. Cloverland's AMR system is designed to establish stable communications between the "smart" devices and the main office/hub. The co-op's system employs the flexibility to accommodate future development and additions to the system. Utilization of standard TCP/IP protocols allows full scalabilty with capable devices. The system uses a blade server for potential expansion requirements. Additional meters will not require system upgrades. Substation sites are modified to accommodate any future AMR or communications changes. Such modifications are done along with Spill-proof and Prevention Control (SPPC) substation upgrades, thereby minimizing the cost.

The expected benefits from this metering upgrade include the ability to leverage transportation costs, standardizing of consumption periods, near-instant low-cost ad-hoc meter reads, outage management, proactive system restoration, control of losses due to tampering, maintenance of correct phasing, future remote switching and voltage monitoring.

Currently, Cloverland has installed the new technology on 50 percent of the meters with 30 percent of the substations retrofitted and operational. Full deployment of the new system is expected to be completed in the third quarter of 2007.

4.11 Alger Delta Cooperative Electric Association

Alger Delta serves approximately 10,300 electric meters and began installing AMR technology in 2003. The co-op elected for the full deployment of the Hunt Technologies TS2[93] system.

The TS2 system is a fixed PLC system. Alger Delta has completed installation of approximately 9,500 out its 10,300 meters.

The Hunt TS2 system provides continuous endpoint communication that provides end-of-line voltage monitoring as well as outage and restoration detection and full two-way communications. Alger Delta currently uses the system for meter reading only.

Once the AMR is fully deployed the cooperative will implement outage and restoration management as part of its AMR program.

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[93] For more information on the Hunt system, go to http://www.hunttechnologies.com/product_specs.asp#ts2.

4.12 Midwest Cooperative

Midwest Energy has a fully implemented TWACS AMR installation. Midwest has over 35,000 AMR meters installed on 30 substations. TWACS utilizes power line carrier technology to reach all of the company's meters, no matter how remote. TWACS provides daily usage, hourly profile usage, voltage reads, outage information, blink counts, demand side management, and remote disconnects with the speed and accuracy that Midwest members demand.

Midwest has previously used contract meter readers to get billing information. Manual meter reads incur problems with employee turn over, weather delays, and vehicle problems. AMR has eliminated these problems and gives Midwest customers accurate bills that virtually never need estimated.

Midwest has had great success in using the system to help customers with high bill complaints. Since it is possible to determine how much a member uses every day or even every hour, the customer can be shown exactly when and how they used the electricity and problems can be pinpointed.

Midwest uses the TWACS system for power quality issues several ways. During outage situations, the company can "ping"[94] meters to determine if the problem is occurring on the company or customer side of the meter. Blink counts are compiled daily, which helps to proactively trouble shoot blink problems or get accurate information when complaint calls are received. The system has even detected outages before the customers.

Midwest is also utilizing the system for demand side management. In the recent heat wave grid emergency, Midwest controlled over 5,000 water heater switches and dropped approximately 5 MW of the peak. This system is much more efficient for load management because it has a two way communication system. The company's old switches needed to be tested every few years for proper operation. With the TWACS system, repairs can be directed to switches that don't "answer." This permits more timely repairs and avoids inconvenience to members who have working switches.

Midwest has been working with Aisen, a division of Toyota, on a residential turbine and have used the load profile information from the TWACS meters to help determine what size turbine would be the most economical and useful for the customers.

Midwest utilizes a TWACS disconnect device on customers that have difficult to access meters or customers that are repeatedly disconnected for non-payment. This saves Midwest the expense of trips to customer's premises for disconnects.

[94] Packet Internet Groper (ping) is a computer utility that checks the quality of a link or verifies the connection of a machine to the Internet

4.13 Cherryland Electric Cooperative AMR (Implementation in Progress)

Cherryland Electric Cooperative (CEC) serves approximately 31,675 meters. To date CEC has installed approximately 8,000 TWACS meters on its system and is in the first year of a four year total system conversion. CEC is considering moving up the project to a three year time frame. The TWACS system is a two-way power line carrier system that delivers data in two directions over the utility's power lines. The current effort does include outage management and load control. Distribution automation will be a separate project once the system is fully deployed.

4.14 Michigan Public Service Commission Activities

4.14.1 Distributed Generation Interconnection Standards

The Michigan Customer Choice and Electricity Reliability Act (2000 PA 141) directed the Michigan Public Service Commission (MPSC or Commission)to establish standards, "for the interconnection of merchant plants with the transmission and distribution systems of electric utilities . . . consistent with generally accepted industry practices and guidelines . . . established to ensure the reliability of electric service and the safety of customers, utility employees, and the general public" (MCL 460.10e).[95] The Commission developed rules to govern Electric Interconnection Standards (R 460.481–460.489).[96]

Once the rules were fully developed, Michigan utilities filed interconnection procedures in concert with those rules.[97] These rules generally provide for the procedures Michigan's regulated electric distribution companies must employ when considering interconnection requests. They provide for the application process, basic technical criteria, filing fees, deadlines for the completion of the various steps in the process. The criteria, procedures, and timelines vary for five different categories based on the size of generators and required complexity of interconnections.

In reviewing technologies related to Michigan's 21st Century Energy Plan, it has been assumed that all interconnections with the utility grid must meet all technical and safety requirements. Further, it has been assumed that interconnections must always operate in a manner which assures the safety of all equipment interconnected with the utility grid and the health and safety of all persons who may come into contact with the grid and its interconnected equipment.

Despite interconnection standards currently in place, some applications for interconnections have experienced delays. In response to this, the Commission initiated a proceeding in late October

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95 http://www.legislature.mi.gov/(wgbxkq55zjnwtc2ym2nhu145)/mileg.aspx?page=getObject&objectName=mcl-460-10e.

96 View online at: http://www.state.mi.us/orr/emi/admincode.asp?AdminCode=Single&Admin_Num=46000481.

97 The utility procedures were approved in Cases Nos. U-14085 (for Northern States Power Company – Wisconsin, d/b/a.Xcel Energy), U-14091 (for Indiana Michigan Power Company, d/b/a American Electric Power), and U-14088 for all other utilities regulated by the Michigan PSC.

2006, Case No. U-15113 to: "(1) investigate the interconnection of independent power producers with a utility's system, (2) identify any problems or deficiencies in the existing interconnection procedures, and (3) develop and implement remedies." In addition, the Commission has directed utilities to file reports on all interconnections and pending applications completed pursuant to the approved procedures, including "whether any problems arose in the process." The Commission also invited interested parties to file, by December 19, 2006, "information detailing interconnection problems they have experienced and any suggestions for changes to the interconnection procedures." And, the Commission directed MPSC Staff to convene a public meeting on this subject on January 9, 2007, and file a report by January 31, 2007, "summarizing the issues identified and making recommendations for future action." MPSC Staff believe this hearing process provides the appropriate venue for determining changes to the current utility interconnection procedures.

4.14.2 Net Metering Program (5-year)

Net metering is an accounting mechanism whereby retail electric utility customers who generate a portion or all of their own retail electricity needs are billed for generation (or energy) by their electric utility for only their net energy consumption during each billing period. Net energy consumption during a billing period is defined as the amount of energy delivered by the Utility and used by the customer, minus the amount of energy, if any, generated by the retail customer and delivered to the utility at the location of the eligible unit. In Michigan, a basic framework for regulated-utility net metering programs was developed through a consensus reached among Michigan utility companies and the MPSC Staff in 2004. That consensus agreement was subsequently approved, with modification by the Commission.[98] These are the basic provisions of the Michigan program: (It should be noted that these provision descriptions include the general outlines of the statewide net metering program. There are some variations in program implementation among Michigan electric utilities. The specific web page for a particular utility should be consulted in order to understand their program in detail).

1. **Total Program Size for Each Utility –** Each Utility will offer a net metering program with a maximum program limit of either 0.1 percent (one tenth of one percent) of the Utility's previous year's peak demand (measured in kW), or 100 kW, whichever is greater.

2. **Duration of the Program –** The net metering program shall be open for customer enrollments for a period of at least five years, and customers who enroll shall be eligible to continue their participation for a period of at least 10 years. Unless the program is changed by the Commission in the meantime, this gives customers until summer 2010 to complete their enrollment in the program. A participating customer may terminate their participation in a Utility's net metering program at any time for any reason.

[98] See http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14346 for copies of all official documents associated with the net metering program, MPSC Case No. U-14346. The Consensus Agreement is document 0001 on that web page, and the Commission Order approving the Net Metering Program is document 0031.

3. **Qualifying Customers and Qualifying Technologies –** Net metering will be allowed for any full-requirements customers of Michigan electric utility companies regulated by the MPSC, on a first-come first served basis, who install qualifying renewable energy generators that are intended to serve their own energy needs. The maximum size generator that can be installed for net metering is less than 30 kW and systems must be sized not to exceed what is needed to serve the customer's self-service needs. Non-dispatchable generation systems (e.g., wind and solar) shall be sized not to exceed the customer's annual energy needs, measured in kilowatt-hours (kWh). Dispatchable systems shall be sized not to exceed the customer's capacity needs, measured in kilowatts.

4. **Net metering is open to all renewable energy source electric generating technologies –** Renewable energy sources are defined by Michigan Public Act 141 of 2000, Section 10g, to include "solar, wind, geothermal, biomass, including waste-to-energy and landfill gas, or hydroelectric." Biomass fueled systems will be allowed to blend up to 25 percent fossil-fuel, as needed to ensure safe, environmentally sound system operation.[99]

5. **Applications, Application Fees, and Interconnection Standards –** Application fees, procedures, and requirements for interconnecting net metering customer generators will be those contained in the Commission's Electric Interconnection Standards Rules (R 460.481-460.489)[100] and the Utility's associated Commission-approved Generator Interconnection Requirements.[101] Some utilities may require additional metering equipment for net metering customers[102]. Program details, including links to obtain guidelines, procedures, and application forms for each utility are included in the descriptions available on the MREP (Michigan Renewable Energy Program) Net Metering web pages[103]

[99] Larger renewable energy systems can be installed and interconnected with the utility grid in Michigan, but they will not be eligible for net metering treatment. MREP has developed a web page to explain Interconnection and Rate Options for Non-Net-Metered Renewable Electric Generators in Michigan at http://www.michigan.gov/mpsc/0,1607,7-159-16377_43420---,00.html.

[100] MPSC Interconnection Standards Rules are available on the Internet at http://www.state.mi.us/orr/emi/admincode.asp?AdminCode=Single&Admin_Num=46000481&Dpt=&RngHigh=48702110.

[101] Available online at, http://www.michigan.gov/mpsc/0,1607,7-159-16393_38274-126214--,00.html.

[102] The Commission approved Interconnection Procedures for Michigan utilities in August 2004 Orders in Cases No. U-14085 (Northern State Power Company – Wisconsin, doing business as (d/b/a/) Xcel Energy), see http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14085; Case No. U-14088 (Alpena Power Company, Consumers Energy company, The Detroit Edison Company , Edison Sault Electric Company, Upper Peninsula Power Company, Wisconsin Electric Power Company, d/b/a We Energies, Wisconsin Public Service Corporation and the Michigan Electric Cooperative Association), see http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14088; and Case No U-14091 (Indiana Michigan Power Company, d/b/a American Electric Power), see http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14091.

[103] http://www.michigan.gov/mpsc/0,1607,7-159-16393_38274---,00.html.

6. **Credits for Net Excess Generation –** In a typical net metering program, there are three categories of energy to consider: (1) energy delivered from the utility to the customer; (2) energy produced by the customer's renewable energy system and utilized on-site; and (3) energy produced by the customer's renewable energy system and delivered to the utility. In Michigan's program, net metered customers will be billed for the first type of energy just as any other similarly situated customer of their utility company. There will be no customer charges for the second type of energy, and no credits from the utility. For the third type of energy, customers will receive a credit equal to the retail power supply charges that the utility charges similarly situated customers. If, at the end of a billing period, the customer has produced and delivered to the utility any energy in excess of what the utility has delivered to the customer and the customer has used, that amount is termed net excess generation (NEG). Generally, Michigan utility companies will credit customers for NEG for an amount per kilowatt hour equal to the utility's retail power supply charges, and that dollar amount will be carried forward as a credit on the customer's next monthly bill. At the end of each year, however, the value of any remaining NEG credits will be claimed by the utility company and used to offset program costs, and the customer's NEG account will be reset to zero.

7. **Renewable Energy Certificates (RECs)[104] –** Customers will be eligible to receive renewable energy certificates for the energy they produce using their eligible self-service generators. Although the original Consensus Agreement included provisions for utilities to own RECs associated with net metered systems, the Commission deleted that portion of the Consensus Agreement when it approved the net metering program.

8. **Utility Reporting Requirements –** Each utility will report to MPSC Staff annually (each September) on: (a) the total number of participating customers in its net metering program; (b) five-digit zip code for each participating customer and starting month and year for each participating customer; (c) technology type and size in kW for each participating customer; (d) total NEG by technology type and cumulative total for each Utility's program (at the end of each 12-billingmonth cycle); and (e) any additional information the Utility believes is necessary in order to properly monitor and evaluate its net metering program. Information that would identify individual customers (such as name, address, account number, etc.) will remain confidential unless the customer gives written permission for such information to be shared.

9. **Program Monitoring and Evaluation –** The net metering program will be monitored and evaluated through the Michigan Renewable Energy Program process. Annual reports will be provided to the Commission and posted on the MREP website, with the first report expected in January 2007.

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[104] For more information about RECs, including a directory of Certificate Marketers, see the U.S. Department of Energy GreenPower Network website, at http://www.eere.energy.gov/greenpower/markets/certificates.shtml.

The table below presents the four main focus areas associated with smart power grid technologies and the various characteristics which were investigated by the Alternative Technologies Workgroup. This is a preliminary guide that begins to provide evaluations of smart power grid technology options, issues, and respective impacts – both negative and positive – on the state's electric utility infrastructure. This is not a comprehensive listing nor includes all of the initiatives currently underway.

Table 1: Characterization of Smart Power Grid (SPG) Technologies

Technology Category	Smart Power Grid Application Description	Technology Options	Implementation Benefits	Barriers To Adoption	Commercial Readiness
	Grid-wide, Two-Way Data Acquisition Infrastructure	Open Standards Architecture; Smart Meters; Commercial Communication Infrastructures; Proprietary Communication Infrastructures; Consumer IP portal (gateway)[2]	Real-time modeling; Self-healing grid; Improved Grid maintenance; Incremental long-term grid reliability improvements.	Cost. Smart Meter adoption is a prerequisite, to facilitate other SPG benefits. Lack of common standards & architecture; Full benefits likely to appear incrementally over time. Limited deployment of some infrastructures.	Smart Meters commercially available; Architecture ready but standards not yet adopted; Common information acquisition model not ready. Limited band width on some existing infrastructures.
Architecture and Communication Standards[3]	EPACT 2005 – Created successor to NERC (ERO)	NERC (ERO) standards development; Enhanced security operations and system hardening.	Efficiency; Security; Reliability; Economics.	Regarding communication infrastructure, "one size does not fit all." Bandwidth, access and security requirements will vary, depending on the applications being considered.	Some segments of technology have settled on "defacto" communication standards. Much work remains, to arrive at open standards for communication and application software.
	Demand-Side Management	Smart Meters; Grid management infrastructure; Appliance monitoring and control.	Improved load management; tariff benefits; cost savings.	Cost; Lack of unified open-standards control and communications architecture; Customer value assessment.	Meters commercially available. Some small scale control architectures available (e.g., through MultiSpeak Initiative). Various communication and control architectures not fully integrated.

Technology Category	Smart Power Grid Application Description	Technology Options	Implementation Benefits	Barriers To Adoption	Commercial Readiness
Monitoring and Load Management	Distribution Monitoring and Control	Smart Meters; Islands of Automation; Line Equip Electronic Controls; Line sensors	Outage Management & Response; Load Characterization and Grid Mgt; Self Healing Networks.	Cost; Lack of unified open standards for control and communication architecture; Limited looped distribution systems – i.e., majority are radial.	Meters commercially available. Some small scale control architectures available (MultiSpeak Initiative). Various communication and control architectures not fully integrated.
	EPACT 2005 Implementation increased facility investment advanced facility technology deployment	Investment in new & expanded R/W; Advanced conductor technology; superconducting technology; automated dist. ckt. reconfiguration	Increased grid capacity; Improved efficiency; Increased reliability;	Jurisdictional conflicts; R/W acquisition delays;	Improved conductor designs are currently available; supercondivity equip. not ready for deployment
	Enhanced DER Management;	Increased deployment of DER (CHP, Wind power, Fuel cells, solar cells); MicroGrid technology development; Ancillary service market improvements	Improved grid control, efficiency & grid stability;	Cost; Siting difficulties; Costs of load following for wind DER; lack of unified grid control architecture; Lack of integrated DER control;	Wind power commercially available; Fuel cell prototype stage;
Advanced Grid Operations	Voltage Support	Planned siting for DER;	Improved grid control, efficiency & stability;	Limited control over siting of new resources;	
	Reactive Support	STATCOM; DSTATCOM; SuperVAR; strategic siting for DER; Local/Distributed VAR Control	Voltage Sag & Flicker support; Real-time grid management	Cost; Application specific; Increased grid management complexity; Market for reactive immature;	STATCOM & DSTATCOM are commercially available; SuperVAR is in prototype; Limited RTO control and siting for reactive sources;
	Load-following Support	Other designated DER facilities;	Improved grid reliability;	Cost; Increased use of DER without load following;	
	Power Quality Support	Advanced harmonic filtering;	Improved power quality for sensitive loads; Improved grid efficiency;	Increased use of harmonic-producing technologies;	

Technology Category	Smart Power Grid Application Description	Technology Options	Implementation Benefits	Barriers To Adoption	Commercial Readiness
	Power Storage	Batteries; Flywheel	Improved grid efficiency;	Cost; Application specific;	
Modeling and Simulation	Grid Management; standardized data structures; improved modeling of DER; improved load forecasting tools; value-based reliability tools; improved generation dispatch models; improved market modeling tools	IT Systems and Application Software Development;	Integration of complex analytical & real-time data to control and maximize grid utilization and reliability; potential software “bugs”;	Costs; Proprietary and incompatible software tools, Lack of available monitoring	“Real-time” tools exist and are used at the Transmission and Sub-Transmission levels. Distribution Tools exist. Modeling and simulation based on historical and predicted loads; dynamic islands of automation becoming more available.