Appendix C

Integration Work Group Report

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Michigan Capacity Need Forum:
Integration Work Group Report

January 2006

Copies of this report are available from the Michigan Public Service Commission's Web site, at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf.

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1 Introduction

The Capacity Need Forum (CNF) was created as a collaborative industry-wide process to assess the projected need for electrical generating capacity in Michigan over the short-, intermediate-, and long-term future and to provide recommendations on the Commission's resource addition policy, if incumbent utilities seek to build additional generation. The Integration work group was responsible for modeling the State's electric generation resource needs and developing modeling scenarios. The process began with a an electric reliability assessment performed by the Midwest Independent System Operator (MISO). The reliability assessment was intended to determine whether Michigan's existing electric generating and transmission assets can satisfy electric reliability standards, given future load growth. The resource expansion modeling involved combining the demand forecast with the inventory of existing resources to determine when a capacity need is likely to develop, to identify the characteristics of the capacity need, and to select the a least cost set or resources the fill the future generation need. In addition, the Integration Group developed a set of scenarios likely to have a significant impact on resource plans, especially risks to which the plans are exposed. NewEnergy Associates was retained by the Integration Work Group to perform the modeling and to assist with data development.

1.1 Reliability Assessment

The reliability assessment was performed by MISO using the MARELI multi-area reliability model. The reliability assessment was performed for the ITC, METC, and ATC regions separately and for ITC and METC (MECS) collectively. The reliability model and results are discussed in part 2 of this report.

1.2 Comprehensive Electric Energy Resource Assessment

The balance of this report, parts 3-10, describe the assumptions, data, model format, and results of the resource expansion study.

The purpose of this Comprehensive Electric Energy Resource Plan 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 fits the needs of the State of Michigan from a reliability and economic perspective. This study was designed to be a comprehensive planning process by evaluating a wide-ranging set of in-state resources and fully modeling economy energy options within the eastern interconnect markets. Unlike traditional Integrated Resource Planning, energy efficiency and renewable (non-traditional generating resources) were not included in a common model run with traditional utility central station options. Instead, scenarios were developed around each of these resource options. This was necessitated in part by our "top-down" approach to estimating energy efficiency performance, and our desire to better understand the cost/performance tradeoffs of various resource options. Selecting a single resource plan based upon cost alone may not provide the best resource plan for meeting future needs. How that plan performs under various scenarios and sensitivities provides valuable information for mitigating risk exposure in the future. Also, the Commission requested that potential options be provided to meet the future demand for electricity in Michigan. The scenario approach can readily be used to identify those options and the tradeoffs incurred in selecting among options.

The Comprehensive Electric Energy Resource assessment exhibited a number of key resource planning results. When Michigan's transmission interconnection capacity is used for economy energy and not for external capacity purchases, the state of Michigan is in need of immediate capacity to meet planning reserve criteria. This need is demonstrated by the model's adoption of two Combustion Turbines, as soon as practical, in 2007. After the model added sufficient capacity for reliability purposes, the model adopted intermediate and base load capacity for the State. As soon as available, the expansion plan selected energy producing, or base load, resources. Combined Cycles were the resource of preference until 2011, when Pulverized Sub-Critical Coal became the preferred resource the first year available due to construction lead time. Throughout the remaining study horizon, Coal was the preferred resource for the State of Michigan. The near term need for immediate capacity to meet planning reserve criteria and the need for intermediate and base loaded energy was further underscored in a variety of sensitivities and scenarios.

2 Reliability Study

The purpose of reliability modeling is to determine whether existing native generation together with existing electric transmission infrastructure and available external generation support can reliably meet projected hourly peak load. Reliability modeling for the CNF was performed by the Midwest Independent System Operator (MISO). The MISO Staff used the Multi-Area Reliability Module (MARELI) computer model from New Energy Associates (A Siemens Transmission and Distribution Company) along with data from the CNF work groups to estimate future generation reliability in each region of the State.

2.1 Reliability Planning

Although reliability standards are not uniformly promulgated throughout the United States, a target of one day in ten years loss of load probability (LOLP) is the most widely acknowledged industry standard. Since electric generating plants are mechanical instruments, they are occasionally prone to failure. 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 plants to meet expected load but one of its generating plants is forced off-line, there will be insufficient generation to meet the expected load. Therefore, a generating reserve is needed to assure that if one unit is forced-off, other units from a reserve are available to meet the expected load.

The likelihood that a generating unit may be forced off-line is manifest 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. Therefore, one goal of utility planning is to identify how much reserves (in megawatts of capacity) are necessary to assure reliability without resulting in excessive fixed costs. These reserves are typically expressed as reserve margin percentage.

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 generation is insufficient in one day out of ten years to meet load. This is the reliability standard that has been adopted by the CNF for generation/transmission planning purposes and the reliability standard used by MISO for the MARELI model runs.

2.2 MARELI Model

The MARELI model is a probability based algorithm used to assess whether a geographic region's native generation, together with interruptible load and impact capability, is sufficient to meet hourly peak loads, within the one day in ten year LOLP tolerance. If the reliability criteria are met, the model gauges the excess import or export capability available. If the criterion is 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. The criterion of one day in ten years translates into 0.1 day in one year in this LOLP calculation.

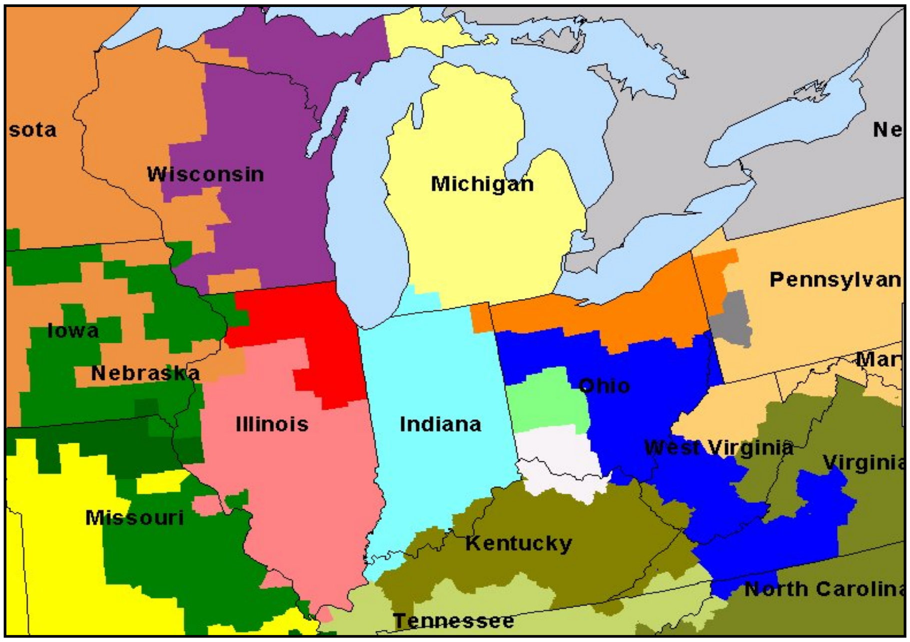
2.3 Michigan Study Results

For the Michigan study, owners of generation reviewed and updated the generation data used by MISO, including capability and availability – incorporating the forced outage experience for each plant. Hourly customer demands were supplied by all MISO load serving entities within Michigan, including investor owned electric utilities, cooperative electric utilities, and municipal electric utilities. Transmission capability was provided by ITC from the results of its power flow modeling and ATC for Michigan's Upper Peninsula. Consonant with the power flow model, the MARELI runs used 2009 forecast data as a base year.

The forecast loss of load probability was first calculated for each study region on a stand-alone basis. Stand-alone means that only native generation was considered available to meet load, and no transmission support was used to support load in the region. After these numbers were calculated, transmission intertie capacity (support from areas with direct ties) was included in the resource mix to meet the peak load. The amount of external support available depends, in part of the country the support is assumed to originate. The following regions were modeled to support the Michigan region: Mid-America Interconnected Network, Inc (MAIN), Mid-Atlantic Area Council (MAAC), Tennessee Valley Authority (TVA), Virginia and Carolinas Reliability Agreement (VACAR). MAIN and MAAC (also known as PJM) are some of the reliability councils defined by NERC (North American Electric Reliability Council). VACAR and TVA are part of the Southeastern Electric Reliability Council (SERC).

For Michigan's Upper Peninsula, transmission support was assumed from Michigan Electric Transmission Company, LLC (METC) and rest of the American Transmission Company (ATC) transmission system.

Figure 2-1: Transmission System Regions



Source: Midwest Independent System Operator

For the Base Case, the stand-alone loss of load probability numbers are shown below:

Figure 2-2: Stand-Alone Loss of Load Probability by Region

METC	.38 days/year
ITC	32.3 days/year
MECS	5.2 day/year
ATC Zone 2	289 days/year

Bearing in mind that the target LOLP is 0.1 day per year, the stand-alone results indicate that all regions violate the reliability standard.

The reliability study was performed a second time to include transfer capability as a source of support for meeting load. Two scenarios were studied. The first assumed phase shifter between Michigan and Ontario were set to allow zero flow to Ontario. The first scenario resulting LOLP's for each Michigan region, and based upon support sourced from various regions around Michigan are summarized in the following table:

Figure 2-3: First Scenario Results by Region

IESO Phase Shifter Flow = 0 MW								
			BaseCase		High Growth		Low Growth	
	Imports	Import		Additional Imports		Additional Imports		Additional Imports
Sink	From	Value	LOLP	Needed	LOLP	Needed	LOLP	Needed
ITC	MAIN	3000	0.69	880	2.2	1540	0.16	None
	TVA	2800	1.03	1050	3.03	1700	0.26	400
	VACAR	2700	1.24	1100	3.55	1800	0.33	450
	MAAC	2500	1.76	1350	4.75	1980	0.51	630
	ALL	2800	1.03	1050	3.03	1700	0.26	400
METC	MAIN	3800	0	(-) 3360	0	(-) 2800	N/A	
	TVA	3500	0	(-) 2645	0	(-) 2375	N/A	
	VACAR	3250	0	(-) 3720	0	(-) 2160	N/A	
	MAAC	3000	0	(-) 2530	0	(-) 1980	N/A	
	ALL	3500	0	(-) 2645	0	(-) 2375	N/A	
MECS	MAIN	3250	0.13	120	0.8	1440	0	(-) 1200
	TVA	3000	0.2	440	1.03	1540	0	(-) 880
	VACAR	3000	0.2	440	1.03	1540	0	(-) 880
	MAAC	2800	0.28	630	1.24	1890	0	(-) 630
	ALL	3000	0.2	440	1.03	1540	0	(-) 880

Source: Midwest Independent System Operator

Based on support from sources external to Michigan, METC satisfies the 0.1 day per year reliability test. MECS only requires 440 MW to meet the standard, but ITC requires an additional 1,050 MW to meet the LOLP standard. ITC will clearly be in violation of the standard, unless action is taken to improve reliability in that region.

Michigan reliability planning is significantly affected by the Ontario energy markets. Power flows originating 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 phase shifters between Michigan and Ontario were set to prohibit power flow between the regions. If this is not the case, then flows to Ontario may significantly increase the amount of needed capacity, because transmission available to Michigan decreases as flow to Ontario increases.

The second scenario is based on phase shifters allowing 1,500 Mw of flow from Michigan to Ontario and, again, allows external transmission support to meet reliability standards. As noted in the "Import Value" column, the amount of transfer capacity for reliability support decreases on an approximately one to one basis when transmission is used to supply electricity to Ontario. Results from this scenario are shown in the table below:

Figure 2-4: Second Scenario Results by Region

IESO Phase Shifter Flow = 1500 MW								
			BaseCase		High Growth		Low Growth	
	Imports	Import		Additional Imports		Additional Imports		Additional Imports
Sink	From	Value	LOLP	Needed	LOLP	Needed	LOLP	Needed
ITC	MAIN	1750	5.62	2080	11.33	2700	2.14	1430
	TVA	1750	same as above					
	VACAR	1500	7.63	2145	14.33	> 2200	3.22	1650
	MAAC	1500						
	ALL	1500	same as above					
METC	MAIN	1000	0.02	(-) 560	0.13	70	0	(-) 1120
	TVA	1000						
	VACAR	1000						
	MAAC	1000						
	ALL	1000	same as above					
MECS	MAIN	1500	1.33	1870	3.9	> 2200	0.3	660
	TVA	1500						
	VACAR	1500	same as above					
	MAAC	1250	1.68	1800	4.87	> 1800	0.43	900
	ALL	1250	same as above					

Source: Midwest Independent System Operator

Under Base Case assumptions, the ITC region experiences a significant violation of the LOLP reliability standards and METC experiences a marginal violation. Collectively, as MECS, the Lower Peninsula, likewise, experiences a violation of the LOLP reliability standard.

The Upper Peninsula's projected 2009 reliability was tested in two scenarios. The first scenario was peak demand, and the second was 70 percent of State-wide peak (off-peak) with the Ludington pumped storage facility in the pumping mode. This scenario tests the U.P.'s reliability when significant parallel flows are created through the U.P. by the Ludington plant in the pumping phase.

Native generation alone is insufficient to maintain acceptable reliability in the 2009 base case and off-peak scenarios. The LOLP resulting from native generation is calculated to be 289 days/year, which seriously violates the target level of 0.1 day/year. The relatively high LOLP is indicative of the mine loads in the region. Mine loads are constant loads so they have a high load factor (ratio of hourly load to peak load). It is not uncommon to find regions with mine loads having load factors as high as 85 percent. To meet the 0.1 day/year LOLP in the off-peak scenario, the U.P. needs an additional 60 MW's of transfer capacity. These results are consistent with previous LOLP studies performed by ATC in this region. These results are shown below:

Figure 2-5: Additional Off-Peak Transfer Needs

	ON PEAK	BaseCase		High Growth		Low Growth	
	Imports		Additional Imports		Additional Imports		Additional Imports
Sink	From	LOLP	Needed	LOLP	Needed	LOLP	Needed
ATC zone2	South (300 MW) **East (50 MW)**	0	(-) 40	0.19	10	0	(-) 80
	OFF PEAK						
ATC zone2	South (210 MW) **East (50 MW)**	1.07	60	4.38	100	0.22	20

Source: Midwest Independent System Operator

The MARELI studies were based upon a "no loss sharing" option. This means that areas adjacent to the study area are assumed to be a source of external support only if that adjacent area had excess reserves to share. Any generation deficiency in an adjacent area excluded support for the study area.

It is also important to keep in mind that the MARELI results measure reliability outcomes only. The model is designed to identify whether additional resources are required, but not the type of resources that most economically meet the need, that is peaking, base load, demand response, or external support through expanded transmission. The type of resource that may most appropriately be added depends on the results of the resource expansion model. A capacity need could be met by additional generation, expanded transmission capacity, implementation of demand response programs, or a combination of these resources.

Finally, the CNF has performed its analysis on a regional basis within Michigan as well as a collectively for the Lower Peninsula, represented by MECS. For reliability planning purposes, this recognizes the role of MISO as the regional reliability coordinator with access to network resources throughout the MISO footprint.

3 Introduction

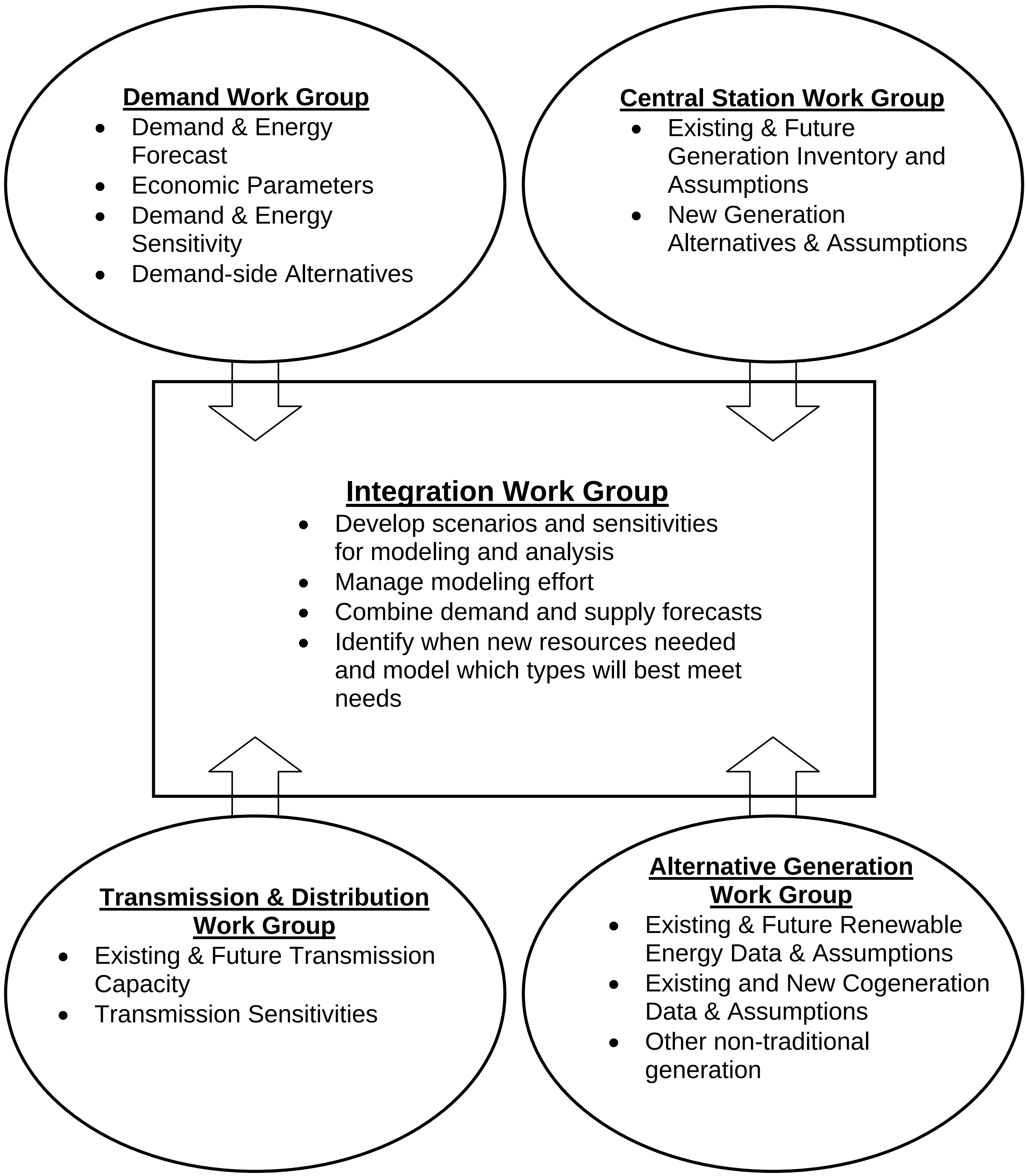
3.1 Capacity Need Forum Integration Working Group Modeling Overview

The Capacity Need Forum (CNF) relied on a three-part modeling effort to assess Michigan's future electric generating resource needs. First, it relied on ITC's MUST analysis to assess transmission import capacity in the base year, 2009. Second, it relied on MARELI reliability analysis performed by the Midwest Independent System Operator (MISO). Third, it relied on NewEnergy Associate's Strategist model to determine the best mix of resources for meeting future needs. Along, with the Strategist model, NewEnergy provided a forecast of future economy energy market prices from sources outside of Michigan.[1]

In order to provide the data necessary to undertake the three-part modeling effort, the Staff established five work groups from among participants to the CNF. Information from the Demand, Central Station, Alternative Generation, and Transmission work groups was provided to the IWG. The IWG completed resource expansion modeling. Figure 3-1 summarizes the work group configuration.

[1] Interconnected electric transmission networks can be used to deliver energy into Michigan, from sources outside the state. Michigan does have limited transmission import-export capacity, however. These issues are addressed by the Transmission and Distribution Work Group (see Appendix G).

Figure 3-1: Capacity Need Forum Work Groups



The IWG developed scenarios and sensitivities and managed the modeling effort. Inputs from the demand forecast and inventory of existing resources were utilized to determine both the timing and type of needs for additional capacity.

3.2 Purpose of the Comprehensive Resource Plan

The purpose of this Comprehensive Electric Energy Resource Plan was to evaluate a broad range of resource options across a number of market scenarios to determine the amounts and types of capacity that are most likely to best fit Michigan's future needs, based on analysis of both reliability and price. The Study evaluated a broad array of in-state resources along with economy energy purchases from out-of-state resources that could be transmitted to Michigan.

3.3 Overview of Integrated Resource Plan Process

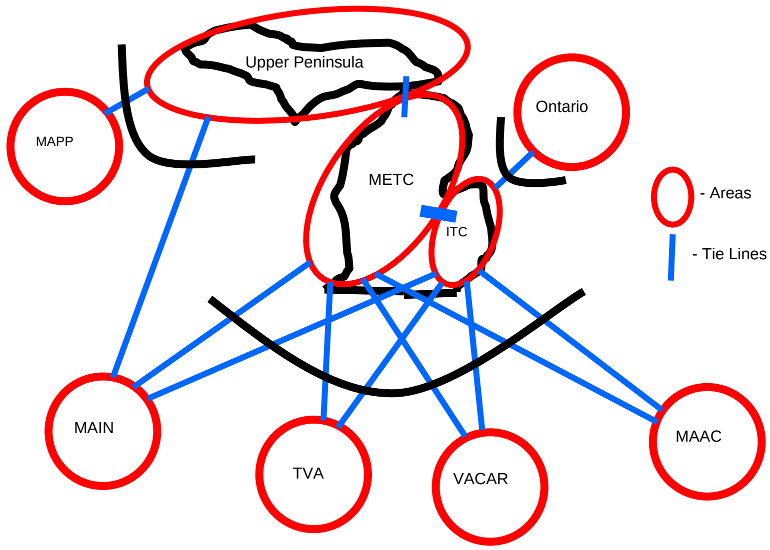
Step 1 Review Planning Policies and Develop Key Assumptions

- Identify and review CNF's Planning Policies 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:
    - Discount rates and inflation rates
    - Fuel prices
    - Load growth
- 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 three Michigan 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, modeling of transmission exchanges, for reliability purposes and for importing and exporting energy and capacity, included ITC and METC collectively, referred to as the Michigan Electric Coordinated System (MECS). Economy energy, in the model, could be sourced from five regions beyond Michigan. This information is summarized in Figure 3-2.

The modeling assumptions did not include access to economy energy from Ontario. Instead, this interconnection was assumed to represent an energy sink in the minimum import sensitivity. Ontario's announced plan to retire approximately 7,000 MW of coal fired generation is one of the contingencies with which the Forum was concerned, and Ontario's energy market was modeled as a reduction in Michigan's import capacity. This contingency is discussed more thoroughly in other sections of this study.

Figure 3-2: Michigan System Representation



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, shown in Figure 2-2, is designed to capture the key transmission constraints within the Michigan transmission system. These constraints are South/North across the Straits and West/East across the Lower Peninsula. The North/South interconnection at the Straits is limited to 50 MW by constraints in the Northern portion of the Lower Peninsula. The West/East transfer capability, previously estimated at 2,850 MW, has recently been enhanced to approximately 4,000 MW in the base case year of 2009. This constraint has been a reliability issue in the past since most, recent generation has been built in the METC regions, but most load is in the ITC region. This imbalance has created transfer constraints in the past.

Data has been collected for the following types of existing and proposed resources:

- Supply-side resources
  - Existing generation units
  - Estimated retirements
  - Optional new construction
- Demand-side resources
  - Existing interruptible loads
  - Existing conservation programs
  - Possible additional interruptible loads
  - Optional additional conservation programs

  (New load management programs were not modeled. It was assumed that new load management may be an appropriate alternative to combustion turbines and, therefore, combustion turbine capacity represents peaking capacity that could be served by these units or, perhaps, by new load management programs.)
- Transmission interfaces
  - Existing capabilities
  - Optional enhancements

The data items compiled for each resource listed above include:

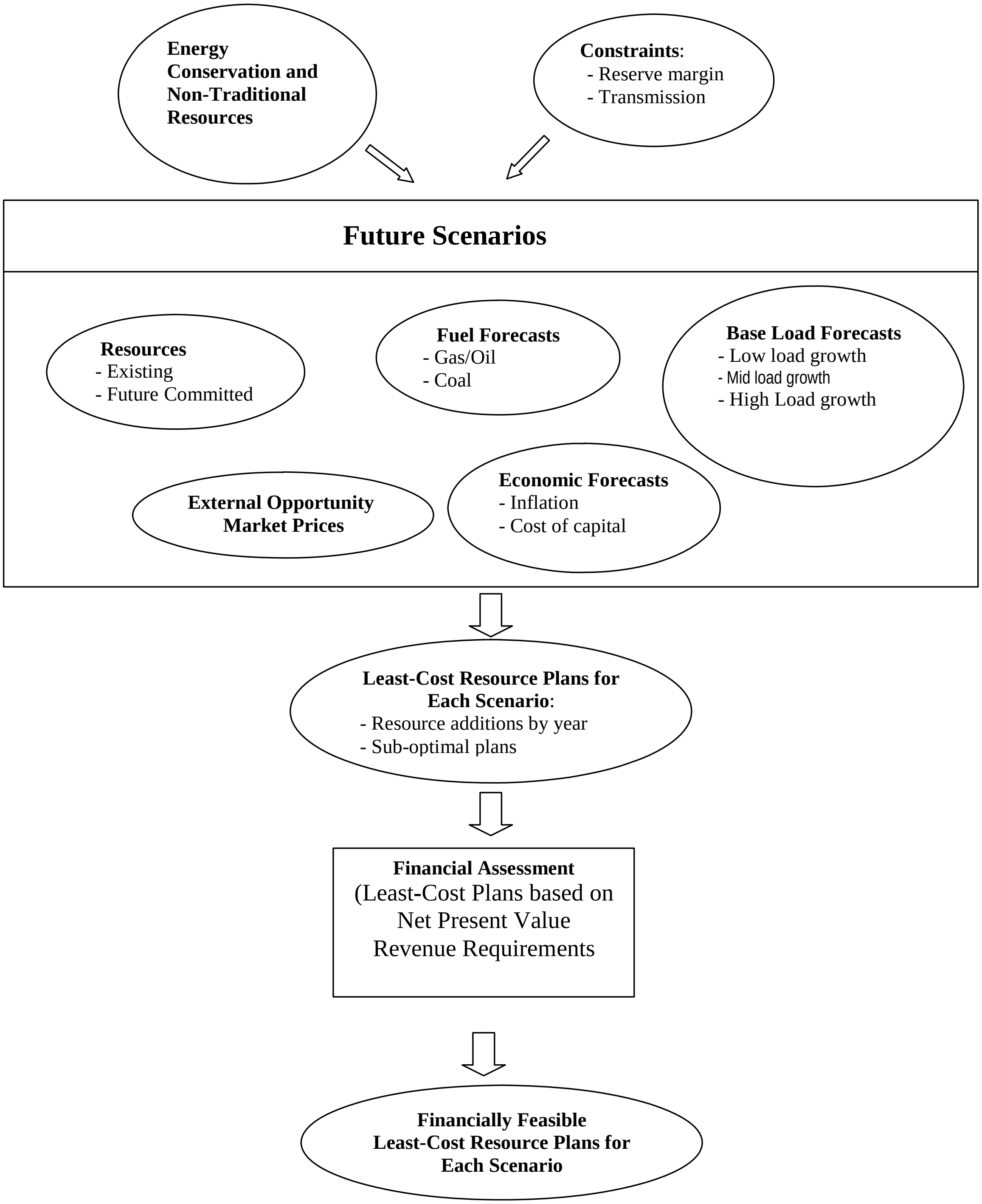
- Load representations
  - Forecast annual energy and peak demand growth
  - Consumption patterns: monthly peaks, energies, and hourly shapes
- Supply-side resource representations
  - Capital cost
  - Construction lead time, annual capital expenditure profile
  - Financing charges (e.g. levelized carrying charge rates)
  - Annual fixed 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 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 emission rates
- Demand-side resource representations
  - Annual energy savings
  - Utility administrative costs (fixed and/or per participant)
- Transmission interface representations
  - Bi-directional MW capacities

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

- Performance measure (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
- Emission constraints
- Sensitivity scenarios

Step 2 Optimize Michigan's Supply-Side Portfolio (w/o new Demand-Side Resources)

Figure 3-3: Optimization Process



Step 3 – Plan Integration

- Screen all available future resource types on a full life-cycle Present Value Levelized $/MWh bus-bar cost.
- Eliminate resources that are unable to compete economically over the study horizon.
- Schedule-in all alternative generation (i.e., Wind, LFG, Anaerobic Digestion, and CHP) and demand-side alternatives.
- Identify robust supply-side resources (resources selected under most scenarios)
- Resources which require short-term capital commitments are of particular concern
- Incorporate a transition period, in the near-term planning horizon, during which the 15 percent reserve margin target should be met.
- Identify key near term resource contingencies for the optional plans based upon quantifiable and subjective criteria:
  - Fuel Diversification
  - Flexibility
  - Other

4 Planning Process

4.1 Planning Tools

The Integration Work Group relied on software developed by New Energy Associates LLC to model electric generation resource needs. New Energy has developed several proprietary planning models to assist with electric capacity planning. The model is comprehensive, allowing comparisons of demand-side measures along with traditional and non-traditional 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 permits one 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 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 attached as Appendix D.

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5 Modeling Requirements

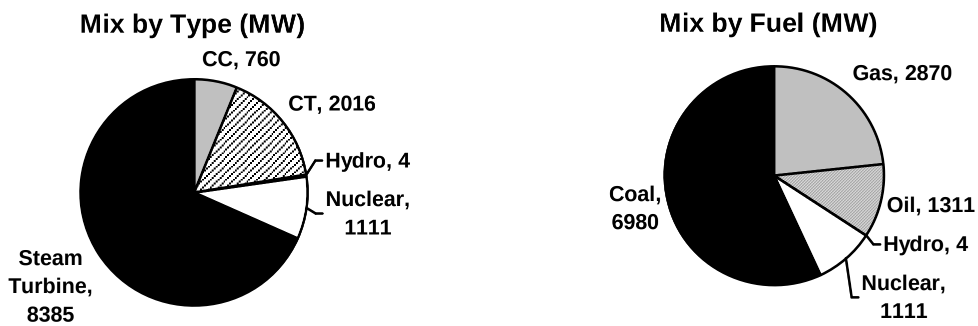
5.1 Existing System

5.1.1 Existing Traditional Generation Resources

All existing native generation was reviewed by Consumers, Detroit Edison, Wolverine, and the Lansing Board of Water and Light. Existing resources consisted of Combined Cycles, Gas Combustion Turbine, Oil Combustion Turbine, Hydro Run of River, Hydro Storage, Nuclear, Pumped Storage Hydro, Coal Steam Turbine, Gas Steam Turbine, and Oil Steam Turbine. The existing resources are contained in Appendix B – Generation Capability Tables.

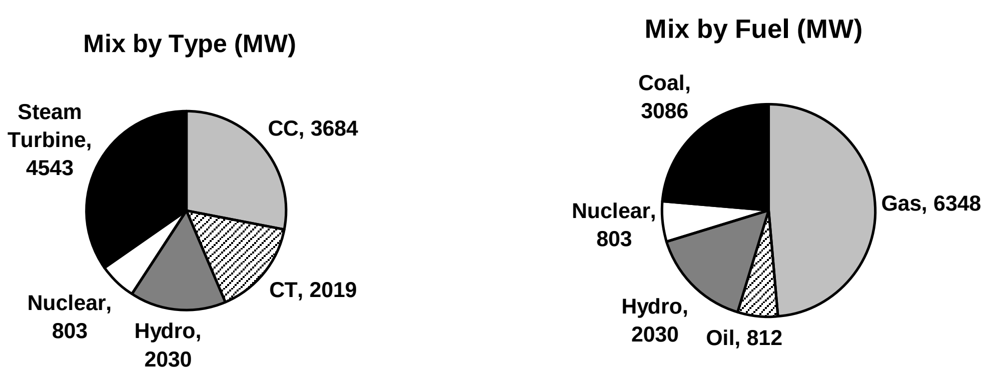
- ITC AREA see Appendix B – Generation Capability Tables Figure B - 1.

Figure 5-1: ITC Existing Capacity Mix



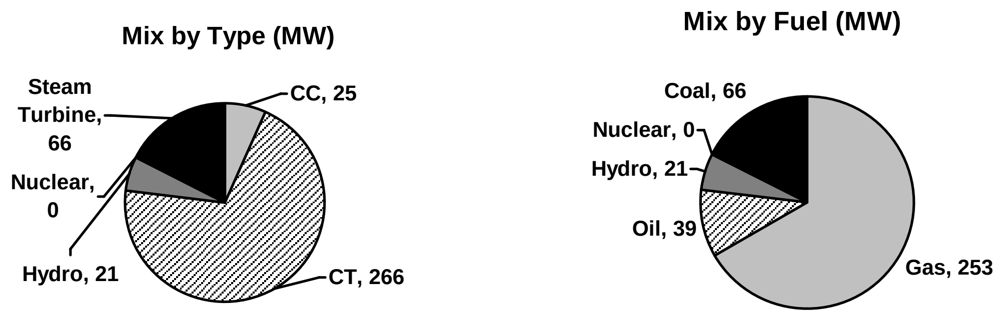
- METC Area see Appendix B – Generation Capability Tables Figure B - 2.

Figure 5-2: METC Existing Capacity Mix



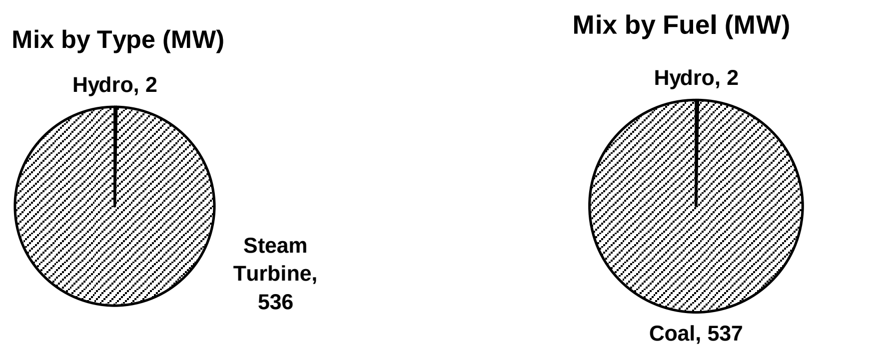
- Wolverine see Appendix B – Generation Capability Tables Figure B - 3.

Figure 5-3: Wolverine Existing Capacity Mix



- Lansing BWP see Appendix B – Generation Capability Tables Figure B - 4.

Figure 5-4: Lansing Existing Capacity Mix

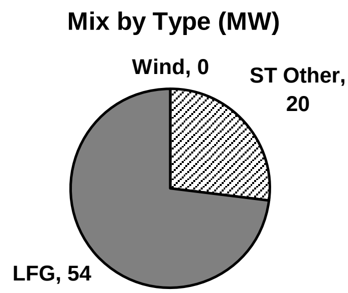


5.1.2 Existing Non-Traditional Generation Resources

All non-traditional generation was reviewed by Consumers, Detroit Edison, Wolverine, and the Lansing Board of Water and Light. Non-Traditional resources consist of Landfill Gas, Anaerobic Digestion, Other Steam Turbine (principally wood fueled), and Wind. The existing resources are contained in Appendix B – Generation Capability Tables.

- ITC Area see Appendix B – Generation Capability Tables Figure B - 1.

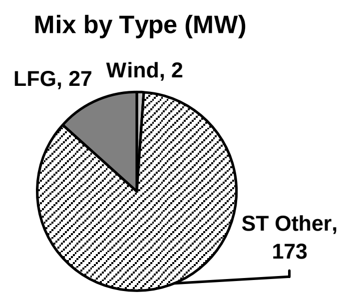
Figure 5-5: ITC Non-Traditional Mix



Note: "ST Other" refers to steam turbine generation, at waste-to-energy plants.

- METC Area see Appendix B – Generation Capability Tables Figure B - 2.

Figure 5-6: METC Non-Traditional Generation Mix



Note: "ST Other" refers to steam turbine generation, at waste-to-energy plants.

- Wolverine see Appendix B – Generation Capability Tables Figure B - 3.
    - No Non-Traditional Generation
- Lansing BWL see Appendix B – Generation Capability Tables Figure B - 4.
    - No Non-Traditional Generation

The Central Station Work Group provided the following assumptions for unit retirements.

- Coal units service life 65 years.
- Nuclear units service life 60 years
- Combined Cycle service life 40 years.

- Combustion Turbine service life 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 detail schedule of unit retirements is outlined in Appendix B – Generation Capability Tables Figure B - 5. For summary purposes, the following table represents the total capacity retirements through the course of the study horizon.

Figure 5-7: Aggregate Unit Retirements

Year	Capacity (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

For the Emissions Case, the IWG assumed an additional 15 percent reduction in Mercury beyond that required by the Clean Air Mercury Rules (CAMR). In this case, we have assumed that Eckert 1-6 will not be able to meet more stringent Mercury reductions and was retired.

5.1.3 Existing Demand-side Resources

No existing demand-side resources were represented.

5.1.4 Existing Transmission Resources

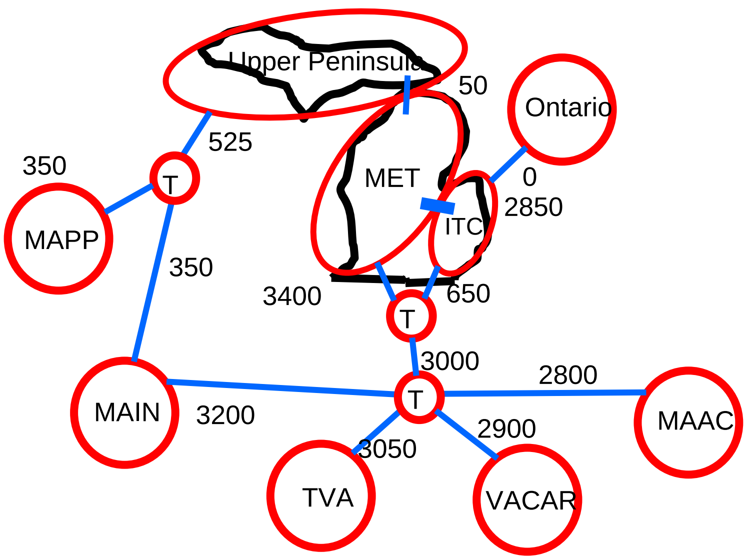
The Transmission and Distribution Work Group was responsible for estimating the transmission import capability into Michigan for the Capacity Needs Forum. The Work Group's specific responsibilities included:

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;
3. Reviewing issues that may have an impact on the State's ability to utilize or expand its transmission system.

The following graphic represents the results of the T&D work group's estimation of import capability. These assumptions were augmented with import capabilities for the Upper Peninsula from ATC[2]. We assumed 50MW of interface capability between the Upper Peninsula to the METC. ATC interface capability with external markets is expected to increase to the following amounts: 224MW in 2005, 300MW in 2006, 325MW in 2008, and 525MW in 2010. These quantities represent on-peak, simultaneous import capabilities.

Figure 5-8: 2010 Transmission Interface Capability [3]



Interface	Capacity	ST from	ST to	Source File
All to MECS	3000	TN Hub	Michigan	CNF_transferstudy_results_05_10_2005 tables.xls
Into METC	3400	TN Hub	METC	CNF_transferstudy_results_05_10_2005 tables.xls
METC to ITC	2850	METC	ITC	CNF_transferstudy_results_05_10_2005 tables.xls
Into ITC	650	TN Hub	ITC	METC to ITC (I344) minus into ITC (I6)
Into Ontario	0	ITC	Ontario	Study Assumption
Notes: "TN" means transmission node hub. "ST from" means source for a transmission transaction and "St to" means the sink of a transmission transaction				

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

5.2 Resource Options

5.2.1 Options Overview

The Central Station working group selected the base technologies for traditional utility generation options. The generation options include:

- Pulverized coal (super-critical and sub-critical)
- Circulating Fluidized Bed Boilers (CFB)
- Nuclear
- Integrated Gasification Combined Cycle (IGCC)
- Traditional 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.

5.2.2 Generation Options

The following table summarizes the Central Station Working Group's estimate of costs for the generation options. All dollar figures are represented in 2005 Dollars.

Figure 5-9: Generation Options Cost Table

Type	Capacity (MW)	Construction ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Construction Lead Time
PC, Sub-critical	500	1,370	42.97	1.80	9,496	6 years
PC, Super-critical	500	1,437	43.60	1.70	8.864	6 years
Fluid Bed	300	1,505	44.70	4.24	9,996	6 years
IGCC	550	1,647	59.52	0.95	9,000	6 years
IGCC-PRB	550	1,845	59.52	0.95	10,080	6 years
Nuclear	1,000	2,180	67.90	0.53	10,400	11 years
CC	500	467	5.41	2.12	7,200	5 years
CT	160	375	2.12	3.71	10,450	3 years

The Work Group 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 eastern and

PRB coal. The following table summarizes the Central Station Working Group's estimate of emissions for the generation options.

Figure 5-10: Generation Options Emissions

Type	SO_2	NOx	Hg	CO_2
PC, Sub-critical	0.05	0.08	1.22×10^{-6}	201
PC, 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	0.00	0.00	0.00	0.00
CC		0.03	0.00	120
CT		0.03	0.00	120
Note: All units expressed in pounds of emissions per million Btu input.				

5.2.3 Other Assumptions

To more accurately represent the expected operating costs of Combined Cycle Generation, $20.52/kW (2005) was added to the plant's fixed O&M to represent the cost of reserving annual pipeline capacity. Pipeline capacity is needed to support the transmission of gas from Louisiana to Michigan. For Combustion Turbines, $5.13/kW (2005) was added to the 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 was added to the commodity price for gas delivered under the reserved pipeline capacity.

In addition to more stringent mercury emissions standards, the Emissions Scenario included a regulatory carbon tax. As a strategy to address the carbon dioxide tax, three plants were modified to capture carbon. The following table of costs represents the modifications to the existing generation options for carbon sequestration. All dollar figures are represented in 2005 Dollars.

Figure 5-11: Coal Sequestration Cost Table

Type	Capacity MW	Construction $/kW	Fixed O&M $/kW	Variable O&M $/MWh	Heat Rate Btu/kWh	Construction Lead Time
PC-Super	500	2,502	75.87	2.95	12,437	6 years
IGCC	550	2,299	73.38	1.18	10,959	6 years
IGCC-PRB	550	2,575	73.38	1.18	12,274	6 years

All future generation options include a transmission interconnection fee based on 5 percent of the capital investment for a generic coal unit ($74.49/kW, 2005 Real Dollars). This is in addition to the onsite transmission related costs that are included in the construction costs shown in Figures 4-9 and 4-11.

5.2.4 Non-Traditional Options

The Alternate Generation Resource Option Group was responsible for compiling an inventory of existing renewable energy, distributed generators, combined heat and power (CHP), and other generation resources in Michigan. The group was 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 Alternate Generation Resource Option work group provided estimates for the capacity potential for renewable resources, investment costs, operating costs, and operating characteristics. Non-Traditional options considered for this study include: Landfill Gas, Anaerobic Digestion, On-shore Wind, and cogeneration.

The following table outlines the schedule of cumulative estimated available capacity (MW) by renewable resource type.

Figure 5-12: Renewable Capacity (MW)

	LFG	Digestion	Wind	CHP
2006	24	10	99	0
2007	47	20	198	68
2008	71	31	272	137
2009	94	41	346	205
2010	118	51	420	274
2011	120	51	420	342
2012	123	51	420	410
2013	126	51	420	479
2014	128	51	420	547
2015	131	51	420	547
2016	134	51	420	547
2017	136	51	420	547
2018	139	51	420	547
2019	142	51	420	547
2020	145	51	420	547
2021	147	51	420	547
2022	150	51	420	547
2023	153	51	420	547
2024	155	51	420	547

Landfill Gas and Anaerobic Digestion were assumed to operate at a capacity factor of 65 percent. Wind was estimated to operate at a capacity factor of 25 percent and Cogeneration was estimated to operate at a capacity factor of 95 percent. All non-traditional 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. Wind was assumed to have zero emissions. Cogeneration, Landfill Gas, and Anaerobic Digestion emissions were assumed to result in zero net emissions.

5.2.5 Demand-side Options

The estimated potential impacts of energy efficiency programs were represented as a resource in the Energy Conservation Cases. Figure 5-13 represents the annual cumulative capacity and energy associated with the energy conservation program. Achievable energy savings for Michigan were based on estimates, including projections of savings calculated by the American Council for an Energy-Efficient Economy (ACEEE). The Working Group utilized only the savings potential estimated by ACEEE from utility programs. This amount was estimated to by 50 percent of the entire savings potential projected by ACEEE for Michigan, and was the amount adopted by the Demand Working Group for planning/modeling purposes. The utilities' costs of the energy conservation programs were estimated to be $110,000,000 (2005$) per year and escalated at GDP.

Figure 5-13: Energy Efficiency Estimates of Capacity and Energy

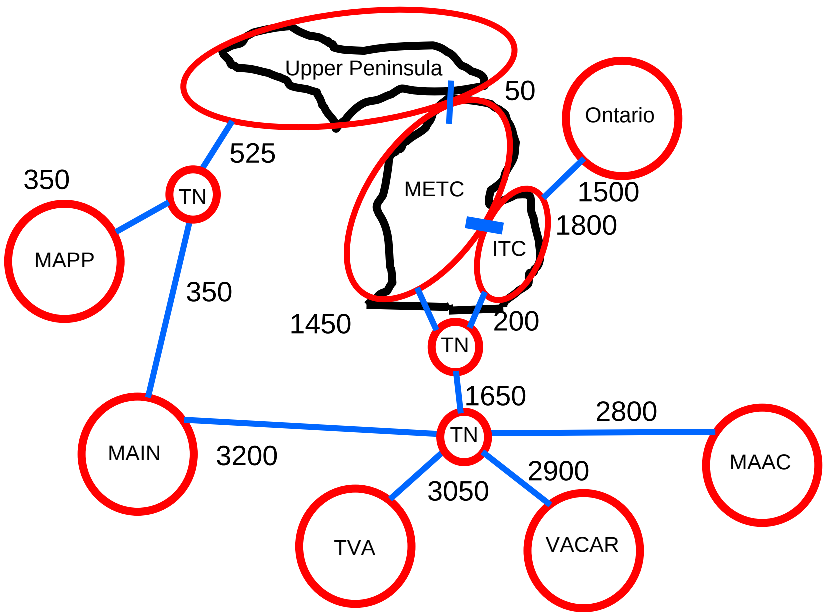
Energy efficiency						
	Capacity (MW)	Energy (GWh)			Capacity (MW)	Energy (GWh)
2006	145	1,108		2016	716	5,465
2007	200	1,523		2017	802	6,122
2008	255	1,943		2018	892	6,807
2009	313	2,386		2019	985	7,516
2010	371	2,831		2020	1,081	8,247
2011	425	3,240		2021	1,100	8,391
2012	479	3,653		2022	1,119	8,537
2013	536	4,086		2023	1,138	8,684
2014	593	4,525		2024	1,158	8,834
2015	654	4,992				

5.2.6 Transmission Options

For the purpose of the Michigan comprehensive resource study, external capacity selling into or from the Michigan market was excluded. The external market was utilized for non-firm economy energy interchange only.

Two transmission scenarios, representing a Low Import and a High Import case, were used. The Low Import case assumed 1500 MW of sales going across Michigan from MISO to Ontario Hydro. Transfers to Ontario, through Michigan, produce significant reductions in transfer capability for Michigan's use from other regions. The following figure represents the impact to transfer capabilities of 1,500 MW flow through Michigan to Ontario.

Figure 5-14: 2010 Low Import Capabilities (MW)



The High Import case assumed adoption of the Tier 1 improvements to Michigan's transmission system. Tier 1 improvements are categorized as southern (external into Michigan) and west/east within Michigan. Transmission projects needed to increase import capabilities into Michigan beyond those included in the base case 2009 projections to the first planning "plateau" are referred to as Tier 1 southern improvements and include:

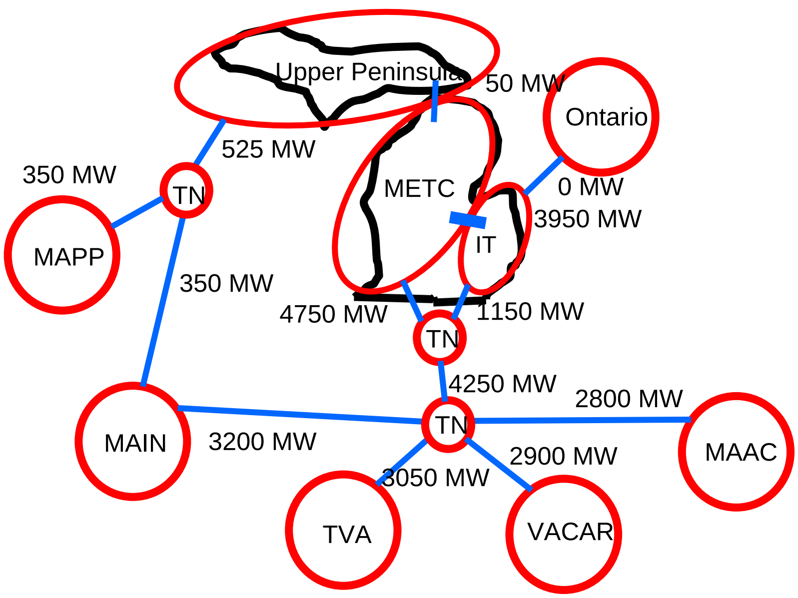
1. Adding transmission in western ITC.
2. Building a station in southwestern ITC, and
3. Reconfiguring some southern ITC circuits.

The west/east Tier 1 METC-ITC upgrades were designed to increase west to east flows within Michigan and include:

1. Building a new 345/230 kV interconnection between the METC system and the ITC system in the northern portion of the METC-ITC interface.
2. Build a new 138/120 kV interconnection between the METC system and the ITC system in the southern portion of the METC-ITC interface.

The following figure represents the impact to Transfer capability.

Figure 5-15: 2010 High Import Transfer Capability



The High Import case assumed Tier 1 improvements with a cost of $100 million to the transmission system. The $100 million cost for Tier 1 upgrades were not included in the costs of the Michigan study. The estimated 2009 transfer capabilities into Michigan's Lower Peninsula under the base, high import, and low import cases are shown in the following table:

Figure 5-16: Key Interface Capabilities

Transmission Interface	Base Case	High Import	Low Import
Into Michigan	3,000	4,250	1,650
Into METC	3,400	4,750	1,450
Into ITC	650	1,150	200
MECS	2,850	3,950	1,800
Note: All units shown in MW.			

5.3 Miscellaneous

5.3.1 System 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. The 15 percent statewide reserve margin criterion is supported by the results of the reliability study performed by MISO. Native generation, together with external support necessary to provide a 1-day in 10 years loss of load probability, equates to approximately a 15 percent reserve margin above forecast peak load for 2009. However, as noted in the reliability section of this study, reliability is affected by the size and availability of generating units among other factors. Differences are likely to exist between regions based on these reliability determinants, and, therefore, differing reserve margins among regions is not unusual.

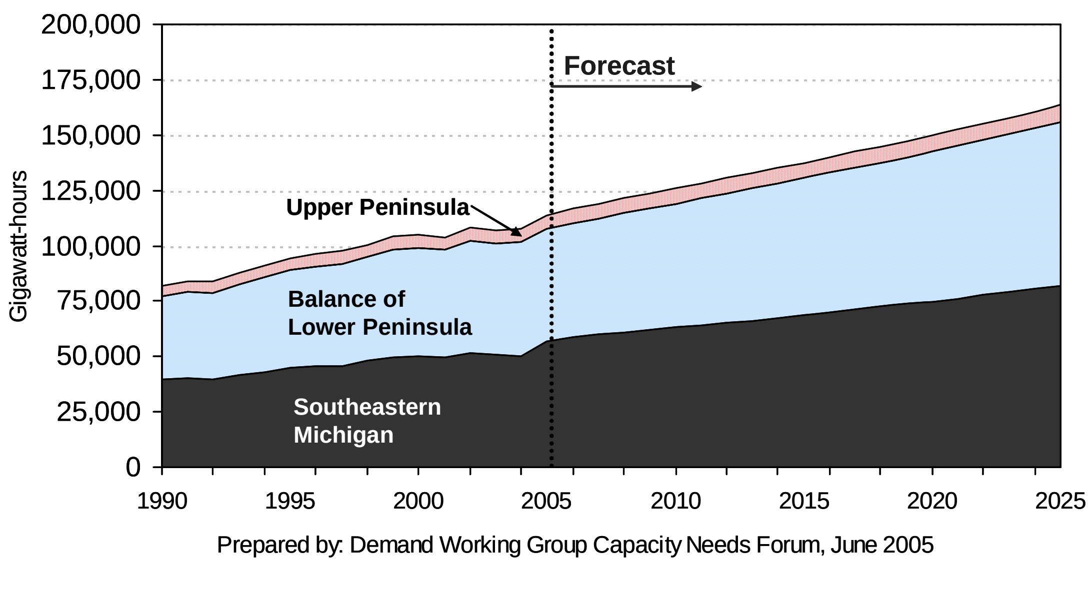
Interchange with the external market represented non-firm spot market purchases and sales of energy only. As indicated previously, no attempt was made to simultaneously include external capacity and economy energy markets.

5.3.2 Demand Forecast

The Demand Work Group was charged with preparing a base electric demand and energy forecast for the period running from 2005 to 2025 for use by the Capacity Need Forum's Integration Group. The projections rely primarily on forecast data provided by members of the working group including: Consumers Energy, Detroit Edison, Wolverine Power Cooperative, Michigan municipal utilities, WE Energies and WPS Energy. Due to the uncertainties in forecasting electric demand, forecast scenarios were also completed by the Demand Work Group base on low load growth and high load growth assumptions.

Michigan's total electricity needs are expected to grow by 1.8 percent from 2005 to 2025, from 113,782 GWh to 163,411 GWh.

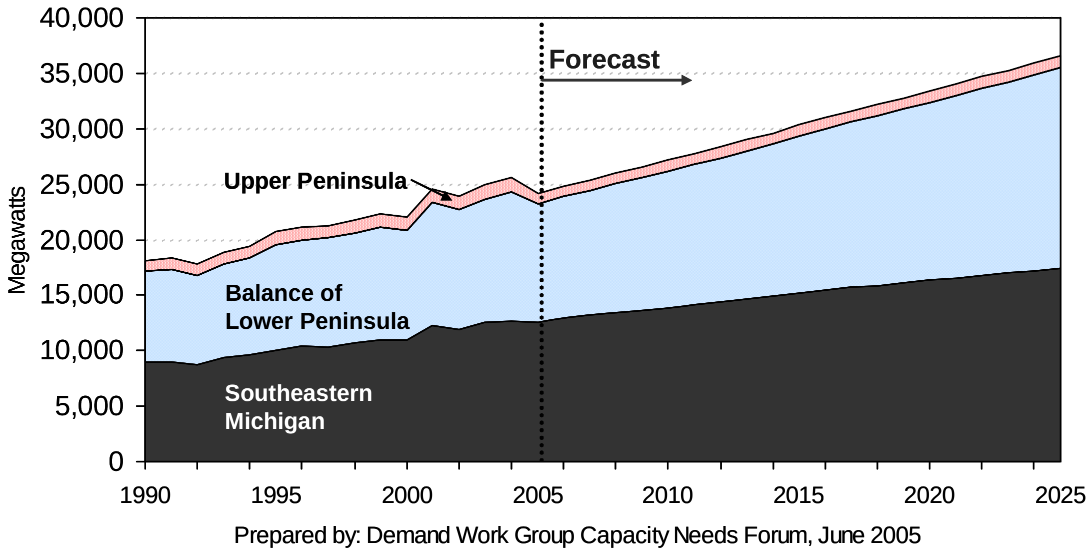
Figure 5-17: Base Michigan Energy Forecast



Prepared by: Demand Working Group Capacity Needs Forum, June 2005

Peak demand is expected to grow from 24,101 MW to 36,589 MW, or at a rate of 2.1 percent from 2005 to 2025.

Figure 5-18: Base Michigan Demand Forecast



5.3.3 Fuel Forecast

5.3.3.1 COAL FORECAST

Delivered Coal forecasts were generated for 10 of the 13 Department of Energy, Energy Information Agency (EIA), defined coal demand regions. These forecasts were sourced from 4 of the 14 EAI defined coal supply regions.

Figure 5-19: Coal Demand Regions

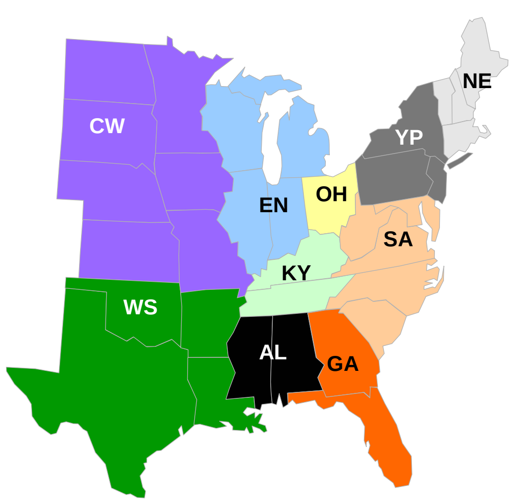
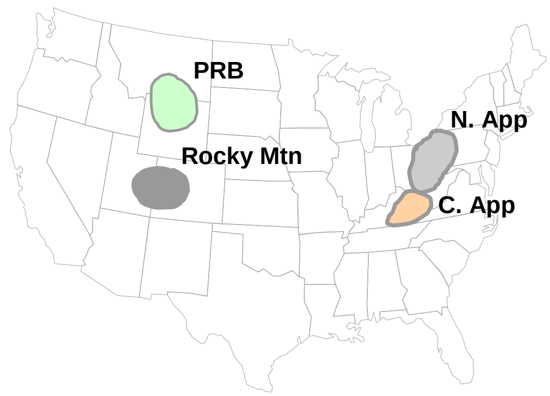


Figure 5-20: Coal Supply Regions



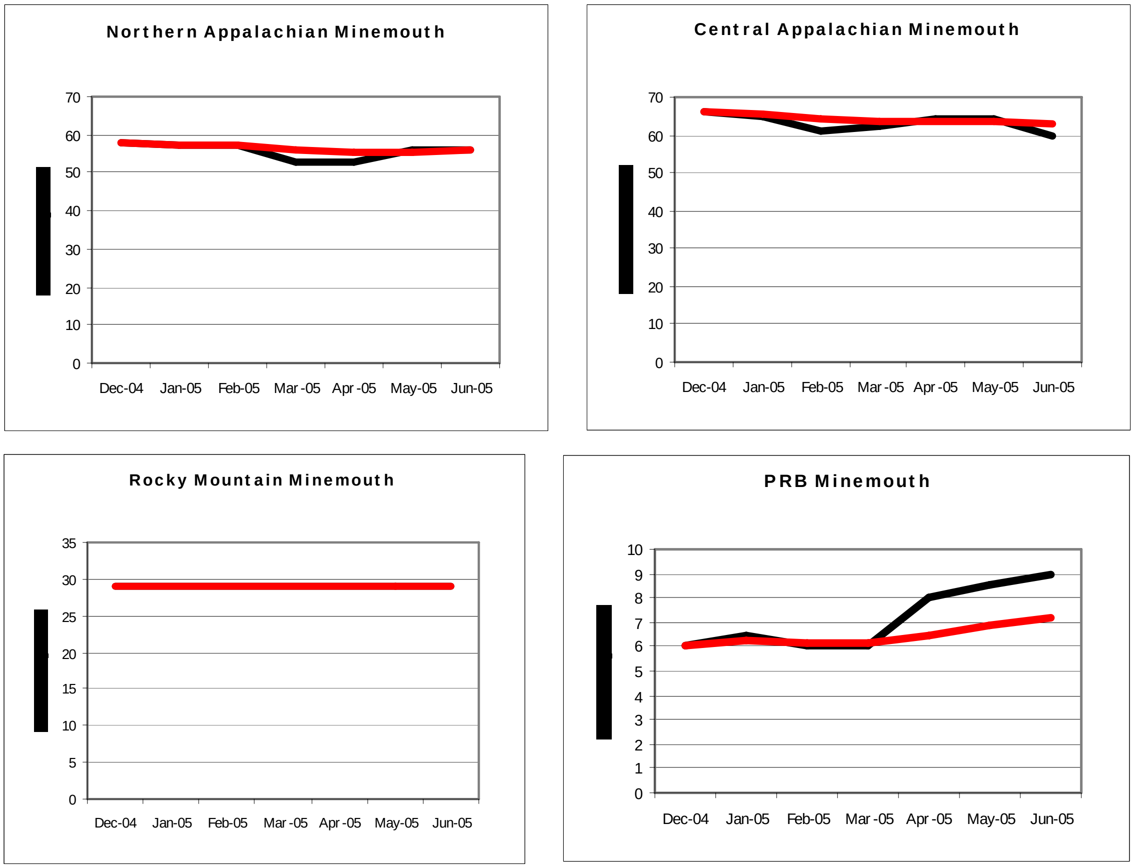
The average transportation cost between each supply and demand region was extracted from the EIA 2005 Annual Energy Outlook. Additionally, a transportation escalation rate of 2 percent was adopted, which is the rate from the EIA 2005 Annual Energy Outlook. The following table enumerates the transportation charges between each of the supply regions and the "EN" region, where Michigan is based.

Figure 5-21: EN Transportation Costs

Demand Region	Supply Region	Average Transportation Cost (2003 Dollars)
EN	PRB	13.05
EN	NA	8.83
EN	CA	10.32
EN	RM	20.68

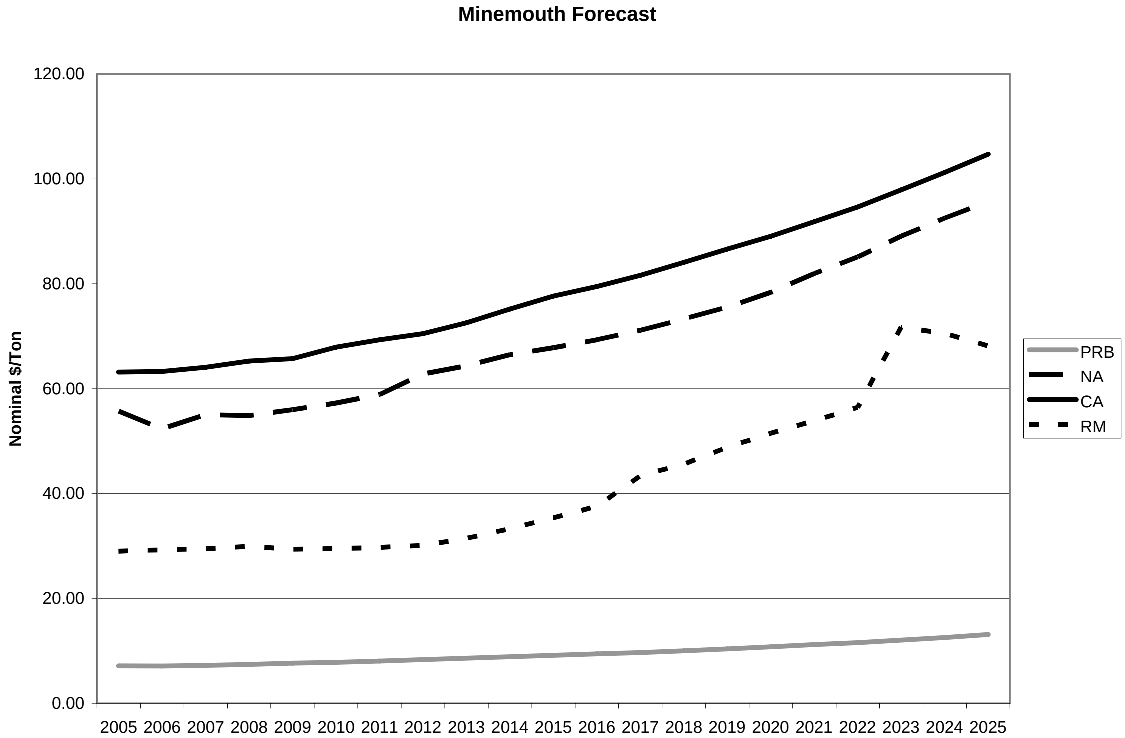
The starting FOB mine price for coal was calculated for the four supply regions within the United States: the Powder River Basin (PRB), Rocky Mountain, Central Appalachia, and Northern Appalachia. For each of the supply regions, the initial coal cost was calculated based on a 7 month average of historical mine mouth prices (December '04 to June '05). This rate was then escalated each year. The annual year-to-year percent change from the EIA 2005 Annual Energy Outlook mine mouth forecast for PRB, Rocky Mountain, Central Appalachian, and Northern Appalachian supply regions were utilized to preserve the base trends of the EIA forecast.

Figure 5-22: Historical Mine Mouth Prices[4,5]



[4] Source: EIA Coal News and Markets
[5] The red line reflect the running average

Figure 5-23: Mine Month Forecast



A blend of coal for each Michigan plant was developed based upon FERC Form 423 and client input. The final delivered price of coal was the sum of the mine mouth forecast and the average transportation charges, weighted by the blend of coal used at each power plant.

5.3.3.2 NATURAL GAS PRICE FORECAST

The starting point for the Natural Gas Price Forecast was the Lower 48 Average Wellhead price forecast[6] from the EIA 2005 Annual Energy Outlook. The process for forecasting Natural Gas prices concluded with a delivered price for 12 EIA defined distribution regions.

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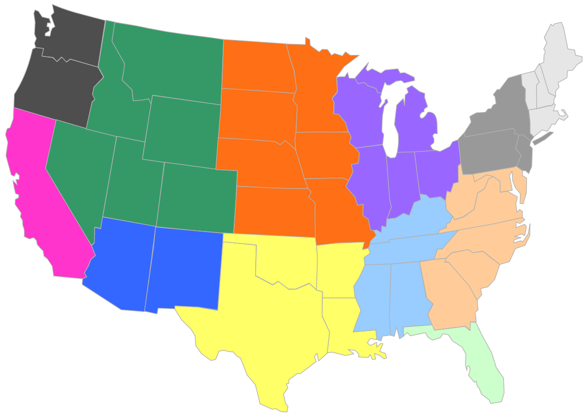
6 Table 102. Lower 48 Natural Gas Production and Wellhead Prices by Supply Region

Figure 5-24: EIA Distribution Regions



The EIA Wellhead forecast was adjusted upward by 12.2 percent to account for the median historical difference between wellhead prices and Henry Hub Prices. The upward adjustment was based on 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 percent difference was used to scale the Wellhead price to Henry Hub. This is the same methodology employed by EIA[7]. The difference between the EIA Delivered Price forecast[8] and the Henry Hub forecast was used to create a matrix of basis points between Henry Hub and the Delivery Regions.

The annual year-to-year percent change from the Wellhead Price forecast from the EIA 2005 Annual Energy Outlook was used to preserve the base trends of the EIA forecast. The starting point for the forecast is based on a rolling one-month average of 18-month NYMEX futures strips (5/16/2005 through 6/23/2005).

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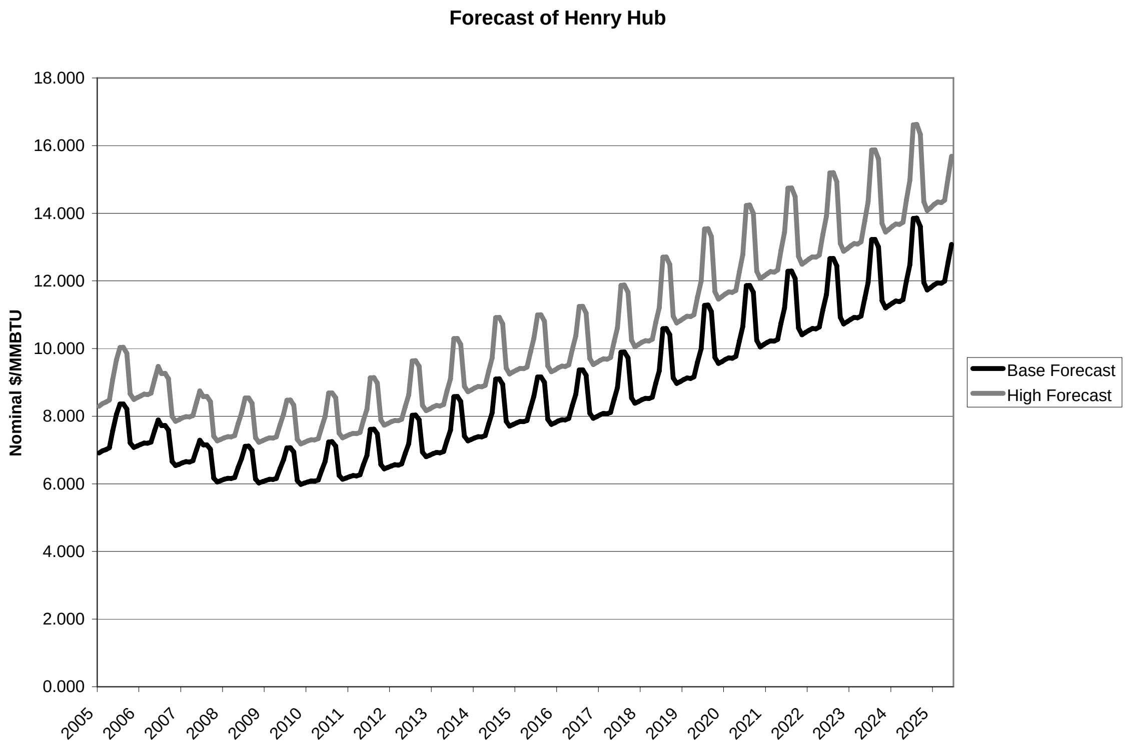
[7] http://www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html

[8] Table 106. Natural Gas Delivered Prices by End-Use Sector and Census Division

Figure 5-25: Natural Gas Price Forecast



5.3.3.3 EMISSIONS PRICE FORECAST

To comply with air emission requirements, the Integration Group did not forecast the cost of retrofitting existing plants with control technology. Instead, the work group calculated the cost of compliance by assuming that the emitting plant would purchase necessary allowances in emission allowances markets. Therefore, forecasts of emission allowance costs were made for each of the primary air contaminants: SO_2, NOx, Mercury, and Carbon Dioxide for the emissions scenario.

The SO_2 price forecast began with the 6-month average of historical index prices (October '04 through March '05) and then escalated at same rate as the 2004 EPA forecast[9] (7.38 percent). The NO_x price forecast began with the 6-month average of historical index prices (October '04 through March '05). The NO_x forecast remains flat until the 2004 EPA forecast begins in 2009. The NO_x forecast then follows the same trend as the 2004 EPA forecast until 2020. After 2020, the same downward trend in NO_x is followed until the end of the study horizon.

[9] Analysis of S. 1844, the Clear Skies Act of 2003; S. 843, the Clean Air Planning Act of 2003; and S. 366, the Clean Power Act of 2003

Figure 5-26: Historical Index Prices

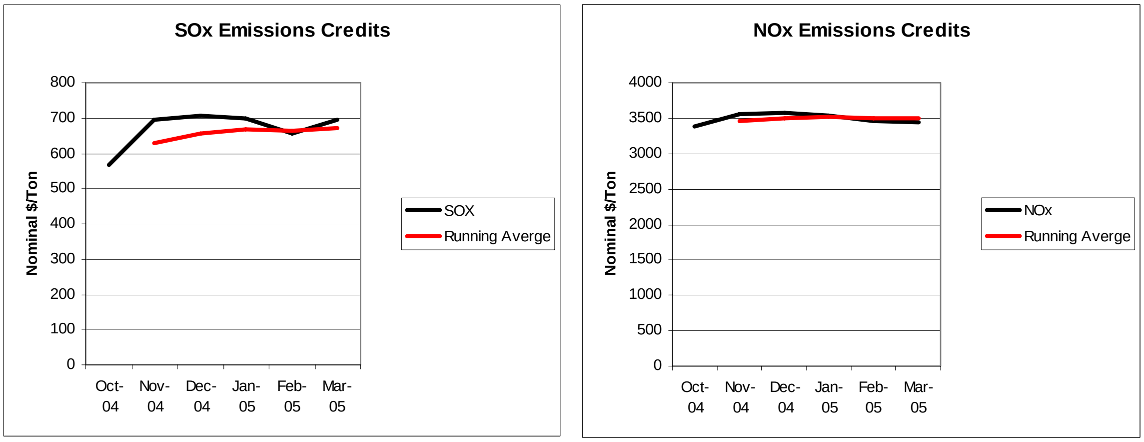
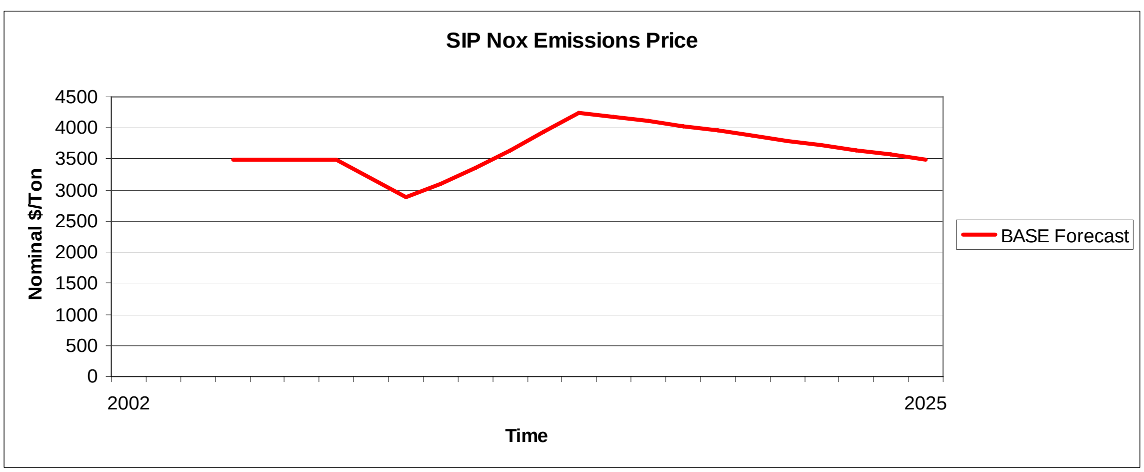


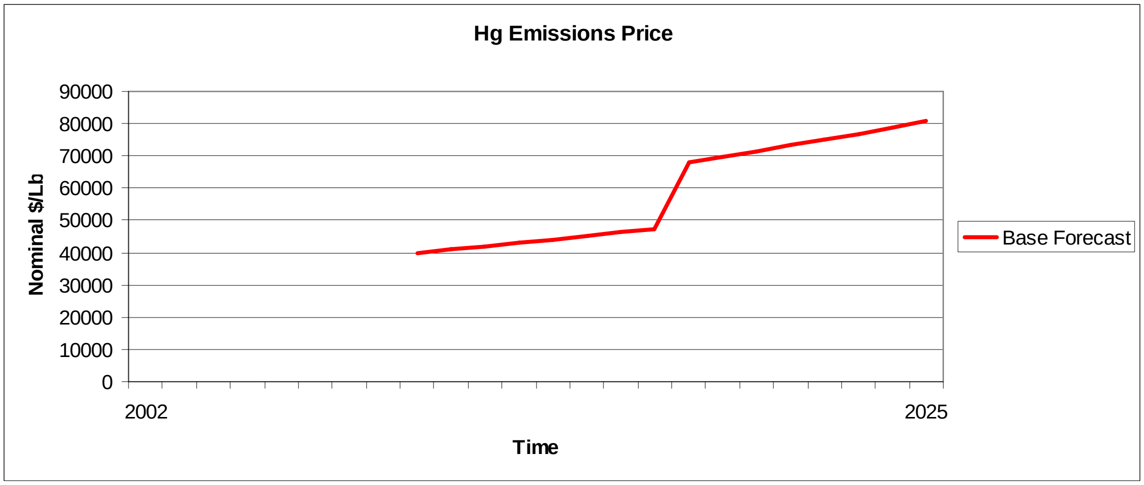
Figure 5-27: SO2 Emission Price Forecast

Figure 5-28: NOX Emission Price Forecast



The mercury (Hg) forecast 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 initiative (CAMR) and was then escalated at the GDP deflator rate.

Figure 5-29: HG Emission Price Forecast

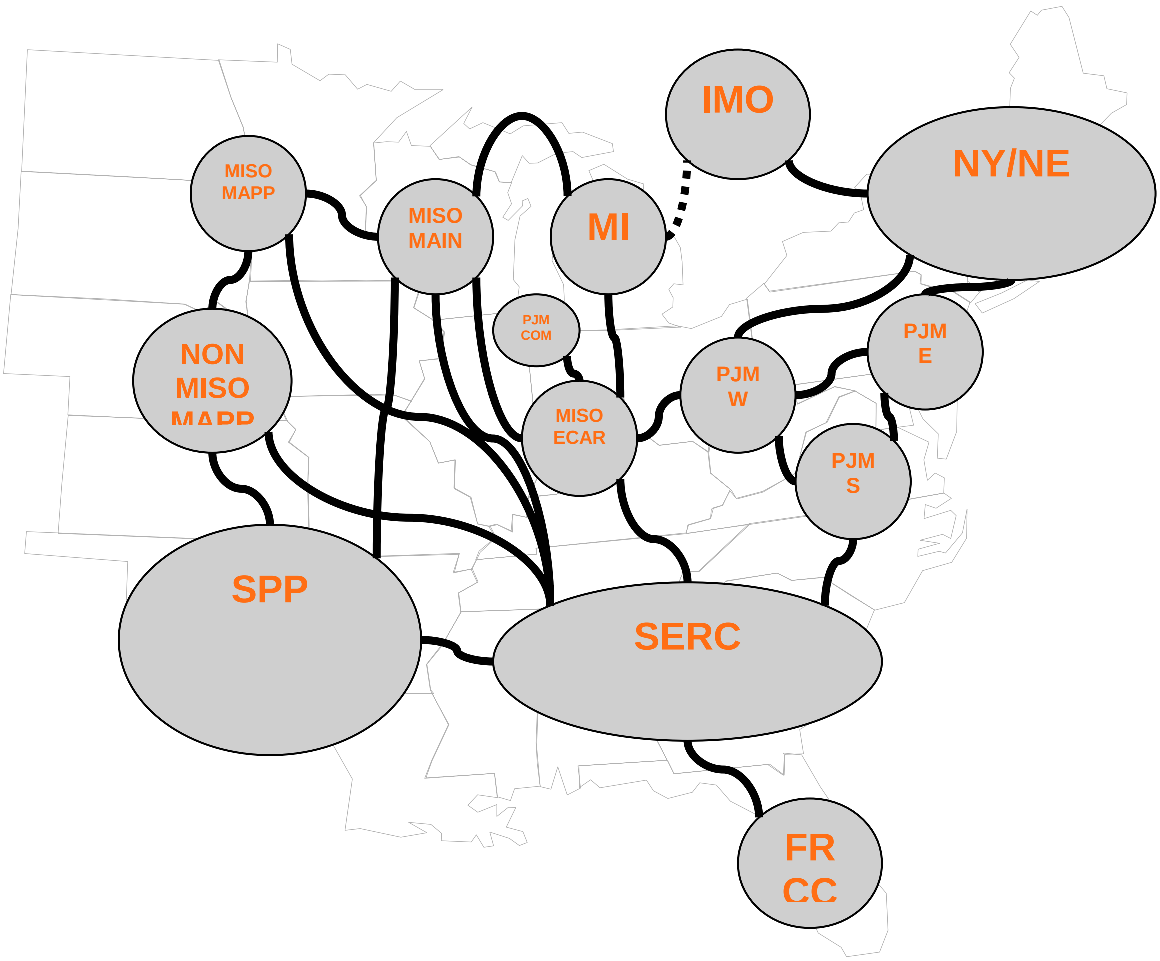


5.3.4 External Market Forecast

The external non-firm energy market forecast was developed using NewEnergy's MarketPower system. MarketPower® is a regional capacity and energy market forecasting system. MarketPower produces the capacity and energy price forecasts. This software simulates regional power markets at a macro-economic level. MarketPower performs the dispatch 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, NUG contract limits, and pumped storage). MarketPower, additionally, assesses when and where new capacity would be added based on market drivers. Existing generators may also be mothballed, restarted or converted to a different technology based on market conditions. Separate prices may be produced for capacity and energy, or a single "all-in" commodity price may be produced.

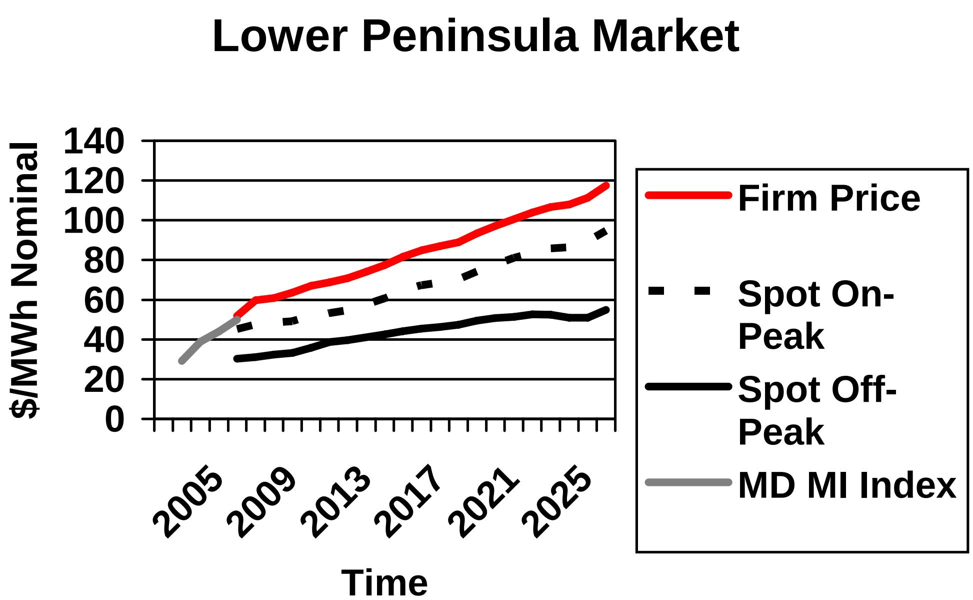
The assumptions for the broader market were consistent with the assumptions made for the Michigan study. The following figure represents the broader regional market:

Figure 5-30: External Market Footprint



The following chart contains the external market price information. The Spot On and Off Peak values represent the external spot energy forecast available to Michigan on a non-firm basis. The Firm price represents an all in price with the value of capacity allocated to all on-peak hours. This forecast is provided as a reference to the Megawatt Daily historical hub price for Michigan. The Megawatt Daily Historical hub price represents a firm 16-hour product.

Figure 5-31: External Market Price Forecast



5.3.5 Economic Forecast

The following table contains the remaining economic assumptions from the Demand Working Group and the Integration Working Group.

Figure 5-32: Economic Assumptions

				Notes:
Construction Escalation			2.47%	Construction Escalation uses GDP
Fuel Escalation	Coal	N. AppAppalachian	2.64%	
		C. Appalachian	2.48%	Fuel Escalations represent delivered costs
		Rocky Mountain	3.42%	
		Powder River Basin	2.29%	
	Gas		2.50%	
	Uranium		2.80%	
Variable O&M Escalation			2.47%	O&M escalation uses GDP
Fixed O&M Escalation			2.47%	
GDP			2.47%	http://www.eia.doe.gov/oiaf/aeo/pdf/aeotab_19.pdf
Debt Interest Rate			9.28%	Calculated to Yield an After Tax Cost Of Capital of 8.04%

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6 Resource Plans

6.1 Overview

The objective function for the Michigan resource plan optimization was to minimize the present worth of utility 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 over the planning horizon. The maximum reserve margin was set to allow the largest alternative to be selected to cover a 1 MW shortfall. In addition, no more than one 500 MW unit was commissioned per area per year.

The table below shows the projected, future reserve margins if no additional resources are added to Michigan's resource portfolio.

Figure 6-1: Lower Peninsula Reserve Margins

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Peak Demand (MW)	22,643	23,285	23,868	24,435	24,997	25,565	26,137	16,725	27,336	27,966
Installed Capacity (MW)	26,029	26,017	26,017	26,017	26,017	26,017	26,017	26,017	26,017	25,897
Reserve Margin	14.96%	11.73%	9.01%	6.48%	4.08%	1.77%	-0.46%	-2.65%	-4.82%	-7.40%

Due to the construction lead times of the resources, the shortest being just over 2 years to construct a CT, and the near term reserve margins on the Lower Peninsula (see Figure 6-1) the actual minimum reserve margin was allowed to fall somewhat below the long run 15 percent minimum required for the study period. The minimum reserve margin was then "feathered" back up to the desired 15 percent by the year 2014 (see Figure 6-2). This was done to avoid overbuilding with CTs (available in 2007), or with CCs (available in 2008) until baseload coal resources become available in 2011.

Figure 6-2: Minimum Reserve Margin Constraints

	2005	2006	2007	2008	2009
Reserve Margin Minimum	14.50%	11.00%	9.70%	9.75%	10.50%
	2010	**2011**	**2012**	**2013**	**2014**
	11.50%	12.50%	13.50%	14.25%	15.00%

The following tables provide an overview of the best plan for each of the scenarios considered in the Michigan comprehensive planning process. Details of all cases are found in Appendix C – Results.

Figure 6-3: 20-Year Summary of Scenarios 2005-2024

Plan Name	Total Capacity Added MW (Firm)	CT Capacity MW	CC Capacity MW	PC Capacity MW	Nuclear Capacity MW	IGCC Capacity MW	Other Capacity MW (Firm)	Ending Reserve Margin %	Ending Peak Demand MW	PVRR 2005 $M
Base	17,040	3,040	3,000	11,000	0	0	0	15.16%	34,880	$ 54, 596.8
Base High Load	21,320	4,320	4,500	12,500	0	0	0	15.00%	38,368	$ 60,895.9
Base Low Load	12,780	1,280	2,000	9,500	0	0	0	15.42%	31,392	$ 48,707.3
Base High Gas	16,880	2,880	2000	12,000	0	0	0	15.03%	34,880	$ 56,282.2
Base High Import	16,900	2,400	1,500	13,000	0	0	0	15.38%	34,880	$ 54,238.5
Base Low Import	16,880	2,880	2,000	12,000	0	0	0	15.03%	34,880	$ 54,870.9
Emissions	16,820	2,720	1,000	4,500	8,000	0	600	15.03%	34,880	$ 66,002.9
Emissions High Load	21,320	2,720	3,000	6,000	9,000	0	600	15.87%	38,368	$ 77,407.4
Emissions High Gas	17,660	2,560	1,000	4,500	9,000	0	600	17.55%	34,880	$ 67,779.9
Energy efficiency	15,799	3,040	2,500	10,000	0	0	259	15.07%	33,722	$ 54,066.4
Energy efficiency High Load	20,139	2,880	4,500	12,500	0	0	259	15.34%	37,210	$ 60,335.7
Energy efficiency Low Load	11,539	1,280	1,500	8,500	0	0	259	15.33%	30,234	$ 48,156.2
Energy efficiency High Gas	15,799	3,040	2,000	10,500	0	0	259	15.22%	33,722	$ 55,639.9
Non-Traditional	17,105	3,520	1,000	0	0	11,550	1,035	15.57%	34,880	$ 57,477.8
Non-Traditional High Load	21,395	4,160	3,000	0	0	13,200	1,035	15.28%	38,368	$ 67,023.5
Non-Traditional Low Load	12,535	1,600	0	0	0	9,990	1,035	15.51%	31,392	$ 53,523.5
Non-Traditional High Gas	17,105	3,520	1,000	0	0	11,550	1,035	15.57%	34,880	$ 59,149.8
Non-Traditional with PC as an option	16,895	3,360	1,000	11,500	0	0	1,035	15.00%	34,880	$ 55,864.4

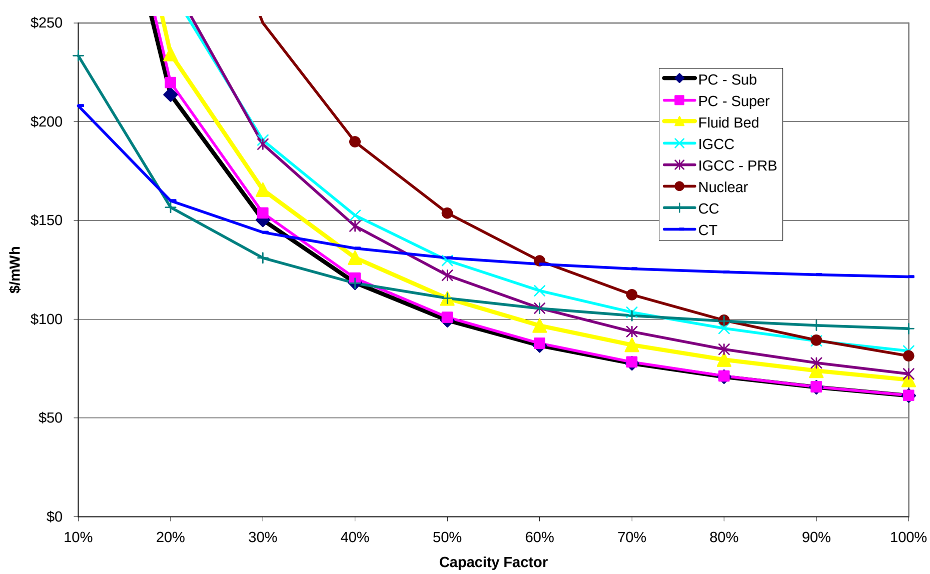
Figure 6-4: 10-Year Summary of Scenarios 2005 - 2014

Plan Name	Total Capacity Added MW (Firm)	CT Capacity MW	CC Capacity MW	PC Capacity MW	Nuclear Capacity MW	IGCC Capacity MW	Other Capacity MW (Firm)	Ending Reserve Margin %	Ending Peak Demand MW	PVRR 2005 $M
Base	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 29,640.9
Base High Load	10,240	2,240	3,500	4,500	0	0	0	15.14%	31,530	$ 32,282.9
Base Low Load	3,500	0	1,000	2,500	0	0	0	16.40%	25,797	$ 27,146.3
Base High Gas	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 30,794.9
Base High Import	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 29,608.2
Base Low Import	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 29,740.4
Emissions	6,680	2,080	1,000	3,000	0	0	600	15.19%	28,664	$ 33,543.9
Emissions High Load	10,180	2,080	3,000	4,500	0	0	600	15.31%	31,530	$ 38,373.4
Emissions High Gas	6,680	2,080	1,000	3,000	0	0	600	15.19%	28,664	$ 34,737.7
Energy efficiency	6,012	1,280	1,000	3,500	0	0	232	15.34%	28,099	$ 29,802.9
Energy efficiency High Load	9,672	1,440	3,000	5,000	0	0	232	15.58%	30,030	$ 34,422.9
Energy efficiency Low Load	2,552	320	0	2,000	0	0	232	15.18%	24,987	$ 27,317.7
Energy efficiency High Gas	6,012	1,280	1,000	3,500	0	0	232	15.34%	28,099	$ 30,873.8
Non-Traditional	6,839	1,760	1,000	0	0	3,300	779	15.86%	28,664	$ 30,368.9
Non-Traditional High Load	10,259	2,080	3,000	0	0	4,400	779	15.10%	31,530	$ 34,728.5
Non-Traditional Low Load	3,249	800	0	0	0	1,650	779	15.88%	25,797	$ 29,187.3
Non-Traditional High Gas	6,839	1,760	1,000	0	0	3,300	779	15.86%	28,664	$ 31,473.1
Non-Traditional with PC as an option	6,879	1,600	1,000	3,500	0	0	779	16.06%	28,664	$ 30,106.3

6.2 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 present value levelized $/MWh busbar cost for each resource alternative over a range of potential capacity factors. The calculations include overnight construction costs, fixed and variable operating costs including fuel costs, construction and operating cost escalations, AFUDC, capital depreciation, property and income taxes, and insurance costs. The Screening Curve for the Base Case cost assumptions is depicted in Figure 6-5.

Figure 6-5: Base Case Screening Curve



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. Similarly, other resource options were screened out of Base, Emissions, Energy Efficiency, and Non-traditional scenarios.

On the basis of this screening curve, the following resources were screened out of the traditional power sensitivity analyses:

- Pulverized Super-Critical Coal
- Fluidized Bed Coal
- IGCC
- IGCC – PRB Coal
- Nuclear

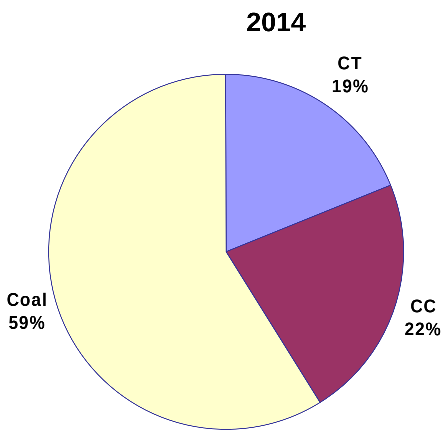
The remaining alternatives: Combustion Turbine, Combined Cycle, and Pulverized Sub-Critical Coal were included in the resource optimization. Note that the Pulverized Super-Critical Coal is

nearly the same cost as Sub-Critical; so the Sub Critical can be thought of as a “placeholder” for coal base load capacity for the purposes of the Base Case.
The results of the base case are summarized below.

Figure 6-6: Base Case Summary Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	3,040
CC	1,500	3,000
PC	4,800	11,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**17,040**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.16
Plan Costs (2005 Million $)		
NPV Utility Cost	$ 29,640.9	$ 54,596.8
NPV Emissions	$ 4,084.0	$ 7,642.3
NPV CO_2	$ 0.0	$ 0.0

Figure 6-7: Base Case Capacity Mix



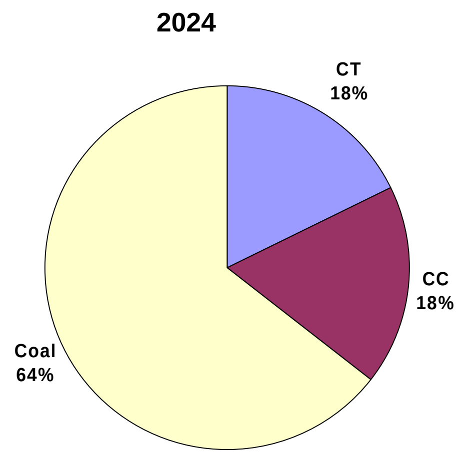


Figure 6-8: Base Case Expansion Plan

Base Case		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
7	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
5	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
10	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	-	1	1
CT - ITC	-	-	-	-	-	-	1	1	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	1	-
CC - ITC	-	-	-	-	-	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	-	1
COAL - ITC	1	1	1	-	1	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

The Base Case Expansion plan exhibited a number of key resource planning results. The state of Michigan is in need of immediate capacity to meet planning reserve criteria. This is exhibited by the fact that 2 Combustion Turbines were added, as soon as practical, in 2007. After achieving the capacity necessary for reliability, the state of Michigan was in need for intermediate and base loaded energy. As soon as available, the Base Case expansion plan selected energy producing resources. Combined Cycles were the resource of preference until 2011, when Pulverized Sub-Critical Coal became the preferred resource. Throughout the remaining study horizon, Coal was the preferred resource for the State of Michigan.

6.3 Sensitivities Analysis

The following sensitivities were performed on the Base Case: High Load, Low Load, High Gas, High Imports, and Low Imports. The High Load sensitivity represented a 2.26 percent demand growth rate; the base case demand growth rate was 1.83 percent. The Low Load sensitivity represented a 1.34 percent demand growth rate. The High Gas sensitivity represented a 20 percent increase in forecasted natural gas prices. The High and Low Import sensitivities were defined in Section 5.2.6. The results of the Base Case sensitivities are contained in Appendix C – Results. The table below shows a summary of the sensitivities from the base case assumptions for the entire twenty-year planning period.

Figure 6-9: Summary of Base Case across all Scenarios 2005-2024
(in MW for each generation type)

Case	CT	CC	PC	Present Value of Renewable Requirement ($ Mill)
Base Case	3,040	3,000	11,000	54,596.8
High Load	4,320	4,500	12,500	60,895.9
Low Load	1,280	2,000	9,500	48,707.3
High Gas	2,880	2,000	12,000	56,282.2
High Imports[10]	2,400	1,500	13,000	54,238.5
Low Imports	2,880	2,000	12,000	54,870.9

The need for immediate capacity for reliability in the form of Combustion Turbines in 2007 was common across all of the sensitivities except the Low Load Sensitivity. As soon as CT's were available for construction, they were built. 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, Combined Cycle (CC) units were placed in service as soon as they could be constructed, which was 2008. The Low Load Sensitivity delayed this need for one year and placed a CC into service in 2009. Coal was built, as soon as available, in 2011 under all scenarios, including the Low Load Sensitivity. This observation underscored the need for base load capacity in the State of Michigan.

Resource construction lead time proved to be a major driver of the expansion plan choices in the near term. As soon as capacity was available, it is built for the capacity needs of the Michigan system, as noted by the addition of CT and CC capacity in the 2007 to 2010 time frame. As soon as coal was a viable option, PC sub-critical units dominate the expansion plan from 2011 through the end of the study horizon.

The High and Low Imports did not make a substantial impact on the expansion plans in the near term. Through 2015, the expansion plans across all scenarios were identical. This was due to the assumption, as stated previously, that no external capacity is bought or sold. One key observation of High Import scenario was that there was approximately $358.3M in benefits associated with greater access to external markets.

6.4 Scenarios

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

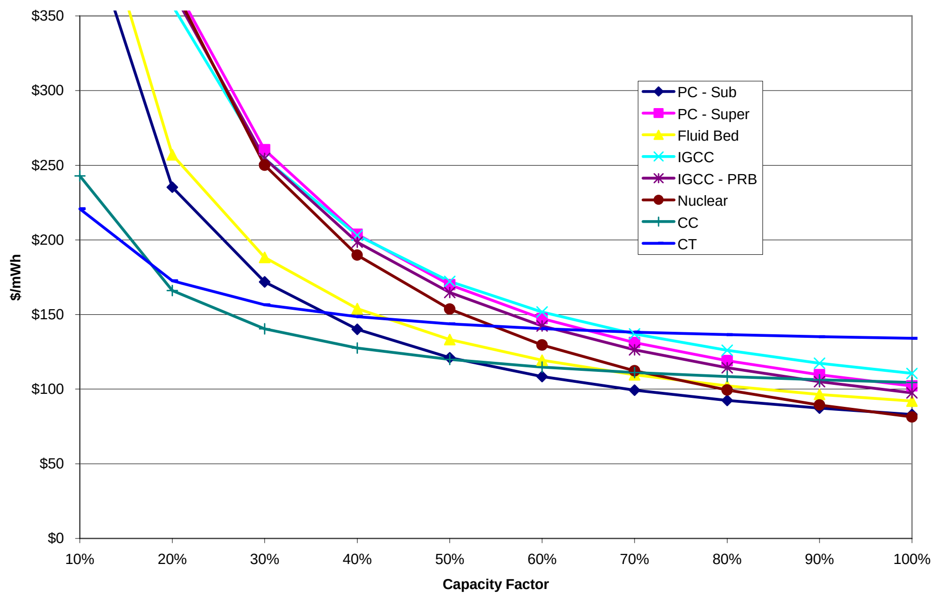
- A 15 percent increase to the Hg emission allowance prices to reflect an additional requirement to reduce Hg emission by 85 percent of CAMR base period levels

[10] Cost figures do not include the transmission investment for TIER 1 improvements

- A Nominal Carbon Tax on CO_2 emissions starting in 2010 at $10/ton and escalating to $30/ton in 2018
- IGCC with CO_2 sequestering is a viable resource option
- Wind and Cogeneration resource are scheduled into the resource mix when available.

The Emissions Case resource options were evaluated on a levelized bus-bar cost to screen out alternatives that would have limited economic viability.

Figure 6-10: Emission Case Screening Curve



On the basis of this screening curve, Fluidized Bed Coal and Pulverized Super-Critical Coal were screened out of the analysis.

The remaining alternatives: Combustion Turbine, Combined Cycle, and Pulverized Sub-Critical Coal, IGCC Sequestered and Nuclear were included in the resource optimization.

Figure 6-11: Expansion Plan Comparison 2005-2024
(in MW for each generation type)

Case	CT	CC	PC	Nuclear	Alternative Sources
Base Case	3,040	3,000	11,000	0	0
Emissions Case	2,720	1,000	4,500	8,000	600

Under the Emission Case, the need for immediate reliability capacity 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 2017. IGCC with carbon sequestration capability was not selected in this scenario because current cost estimates place its fixed cost at more than the fixed costs of a new nuclear unit.

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

Figure 6-12: Emissions Case Cost Components 2005-2024
(in million $)

Case	PVRR	PV Total Emission[11]	PV Total Carbon
Base Case	54,596.8	7,642.3	0.0
Emissions Case	66,002.9	20,195.6	12,751.3

The Emission Case was further subjected to High Load and High Gas Sensitivities.

Figure 6-13: Emission Case Sensitivities 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	CT	CC	PC	Nuclear	Wind/Cogen	Present Value of Reserve Requirement ($ mill)
Emissions Case	2,720	1,000	4,500	8,000	600	66,002.9
High Load	2,720	3,000	6,000	9,000	600	77,407.4
High Gas	2,560	1,000	4,500	9,000	600	67,779.7

6.5 Energy Efficiency

The Energy Conservation Case Scenario was focused on the effects of greater emphasis on energy efficiency investment and energy alternatives. The Energy Conservation Case scenario contained the following assumptions:

- Energy Conservation programs are scheduled in and the cost of the program is incorporated into the present value cost calculation
- No direct load control was included
- Landfill Gas, Digestion, and Wind resources will be scheduled in according to availability

[11] Includes cost of Carbon emissions

The Energy Efficiency Case resource options are shown below:

Figure 6-14: Energy efficiency Comparison 2005-2024

	Capacity Additions by Generation Type (MW)				
Case	**CT**	**CC**	**PC**	**LFG, Digestion, and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	3,040	3,000	11,000	0	54,596.8
Energy Efficiency Case	3,040	2,500	10,000	259	54,066.4

Under the Energy Conservation Case, the need for immediate reliability capacity was still apparent. The longer term need for energy production was met through the addition of Coal resources along with energy efficiency investment. Over the entire twenty year planning horizon, the Energy Efficiency scenario resulted in approximately $500 million in lower present value revenue requirements than the Base scenario.

The Energy Efficiency Case was further subjected to High Load, Low Load, and High Gas Sensitivities.

Figure 6-15: Energy Efficiency Case Sensitivities 2005-2024

	Capacity Additions by Generation Type (MW)				
Case	**CT**	**CC**	**PC**	**LFG, Digestion, and Wind**	**Present Value of Reserve Requirement ($ mill)**
Energy Efficiency Case	3,040	2,500	10,000	259	54,066.4
High Load	2,880	4,500	12,500	259	60,335.7
Low Load	1,280	1,500	8,500	259	48,156.2
High Gas	3,040	2,000	10,500	259	55,639.9

6.6 Non-Traditional

The Non-Traditional Case Scenario was focused on the effects of targeted non-traditional generation alternatives. The Non-Traditional Case scenario contained the following assumptions:

- Mandated renewable portfolio standards: 3 percent of energy in 2008, 5 percent of energy in 2010, and 7 percent of energy in 2015
- Landfill Gas, Digestion, Wind, and Cogeneration resources will be scheduled in according to portfolio standards
- Coal and Combined Cycle resources were not allowed.

The Non-Traditional Case resource options were identical to the Base Case, with the exception of Combined Cycle and Coal technologies. However, due to resource construction lead times, Combined Cycle resources were allowed as a bridge alternative until IGCC units were available in 2011. Given the assumptions for a mandated renewable portfolio as described on the previous page, the non-traditional resources projected to be available in Michigan by the Alternate Generation Work Group (Landfill Gas, Digestion, Wind and Cogen), were unable to meet the requirements. Therefore, each non-traditional resource was scaled-up in order to meet the renewable portfolio standards of 3 percent in 2008, 5 percent in 2010 and 7 percent in 2015. Figure 6-16 reflects the projected available capacity compared to the scaled-up amounts utilized in the scenario.

Figure 6-16: Scaled Up Renewable Capacity

	LFG	Digestion	Wind	Cogen
2006	24	10	99	
2007	47	20	198	68
2008	71	31	272	137
2009	94	41	346	205
2010	118	51	420	274
2011	120	51	420	342
2012	123	51	420	410
2013	126	51	420	479
2014	128	51	420	547
2015	138	54	443	576
2016	145	55	454	590
2017	151	56	463	602
2018	157	58	474	615
2019	164	59	484	628
2020	170	60	495	642
2021	177	61	506	655
2022	185	63	517	669
2023	192	64	528	683
2024	199	66	539	697

Figure 6-17: Non-Traditional Comparison 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT MW**	**CC MW**	**PC MW**	**IGCC MW**	**LFG, Digestion, Cogen and Wind MW**	**Present Value of Reserve Requirement ($ mill)**
Base Case	3,040	3,000	11,000	0	0	54,596.8
Non-Traditional Case	3,520	1,000	0	11,550	1,035	57,477.8

Under the Non-Traditional Case, the need for immediate reliability capacity was still apparent. The longer term need for energy production was met through the addition of IGCC resources.

The Non-Traditional Case was further subjected to High Load, Low Load, High Gas and pulverized coal was made available as an option in the "Coal Available" sensitivities.

Figure 6-18: Non-Traditional Sensitivities 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Non-Traditional Case	3,520	1,000	0	11,550	1,035	57,477.8
High Load	4,160	3,000	0	13,200	1,035	67,023.5
Low Load	1,600	0	0	9,900	1,035	53,523.5
High Gas	3,520	1,000	0	11,550	1,035	59,149.8
Coal Available	3,360	1,000	11,500	0	1,035	55,864.4

The following tables examine the sensitivities across scenarios

Figure 6-19: Base Sensitivities Comparison 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	3,040	3,000	11,000	0	0	54,596.8
Emissions Case	2,720	1,000	4,500	8,000	600	66,002.9
Energy efficiency	3,040	2,500	10,000	0	259	54,066.4
Non-Traditional	3,520	1,000	0	11,550	1,035	57,477.8

Figure 6-20: Sensitivities across High Load Scenario 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	4,320	4,500	12,500	0	0	60,895.9
Emissions Case	2,720	3,000	6,000	9,000	600	77,407.4
Energy efficiency	2,880	4,500	12,500	0	259	60,335.7
Non-Traditional	4,160	3,000	0	13,200	1,035	67,023.5

Figure 6-21: Sensitivities across Low Load Scenario 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	1,280	2,000	9,500	0	0	48,707.3
Energy efficiency	1,280	1,500	8,500	0	259	48,156.2
Non-Traditional	1,600	0	0	9,900	1,035	53,523.5

Figure 6-22: Sensitivities across High Gas Scenario 2005-2024

Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	2,880	2,000	12,000	0	0	56,282.2
Emissions Case	2,560	1,000	4,500	9,000	600	67,779.7
Energy efficiency	3,040	2,000	10,500	0	259	55,639.9
Non-Traditional	3,520	1,000	0	11,550	1,035	59,149.8

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Appendix A – Demand and Energy Forecast

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Figure A - 1: Energy Forecast

Energy Forecast (GWh)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	56,758	50,576	6,448
2006	58,552	51,570	6,526
2007	59,857	52,621	6,565
2008	60,982	53,877	6,624
2009	61,979	54,977	6,684
2010	63,037	56,058	6,754
2011	64,098	57,180	6,821
2012	65,186	58,424	6,875
2013	66,315	59,444	6,929
2014	67,509	60,598	6,991
2015	68,729	61,747	7,053
2016	69,996	63,029	7,116
2017	71,138	64,077	7,180
2018	72,341	65,259	7,243
2019	73,612	66,474	7,306
2020	74,910	67,693	7,370
2021	76,231	68,923	7,434
2022	77,575	70,164	7,499
2023	78,942	71,417	7,564
2024	80,334	72,682	7,632
2025	81,751	73,959	7,701

Figure A - 2: Demand Forecast

Demand Forecast (MW)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	12,551	10,652	898
2006	12,896	10,965	903
2007	13,174	11,285	910
2008	13,415	11,626	918
2009	13,648	11,970	926
2010	13,888	12,313	938
2011	14,125	12,663	946
2012	14,377	13,014	953
2013	14,650	13,367	962
2014	14,939	13,724	971
2015	15,218	14,101	979
2016	15,505	14,484	988
2017	15,697	14,871	997
2018	15,898	15,265	1,008
2019	16,108	15,671	1,016
2020	16,318	16,071	1,025
2021	16,532	16,472	1,036
2022	16,748	16,877	1,044
2023	16,967	17,283	1,054
2024	17,189	17,692	1,063
2025	17,413	18,103	1,073

Figure A - 3: High Energy Forecast

High Energy Forecast (GWh)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	57,325	51,082	6,513
2006	59,723	52,601	6,657
2007	61,652	54,200	6,762
2008	63,421	56,032	6,889
2009	65,078	57,726	7,018
2010	66,820	59,421	7,160
2011	68,584	61,183	7,299
2012	70,401	63,098	7,425
2013	72,283	64,794	7,552
2014	74,260	66,657	7,690
2015	75,601	67,922	7,759
2016	76,995	69,332	7,828
2017	78,251	70,485	7,897
2018	79,575	71,785	7,967
2019	80,973	73,121	8,037
2020	82,401	74,462	8,107
2021	83,854	75,815	8,178
2022	85,332	77,181	8,249
2023	86,837	78,559	8,321
2024	88,368	79,950	8,395
2025	89,926	81,355	8,471

Figure A - 4: High Demand Forecast

High Demand Forecast (MW)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	12,677	10,759	907
2006	13,154	11,185	921
2007	13,569	11,624	937
2008	13,951	12,091	954
2009	14,331	12,568	972
2010	14,721	13,051	994
2011	15,114	13,550	1,013
2012	15,527	14,055	1,029
2013	15,969	14,570	1,048
2014	16,433	15,097	1,068
2015	16,740	15,512	1,077
2016	17,056	15,932	1,086
2017	17,267	16,358	1,096
2018	17,488	16,791	1,108
2019	17,719	17,238	1,118
2020	17,950	17,678	1,128
2021	18,185	18,120	1,139
2022	18,423	18,564	1,148
2023	18,663	19,011	1,159
2024	18,907	19,461	1,169
2025	19,155	19,913	1,180

Figure A - 5: Low Energy Forecast

Low Energy Forecast (GWh)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	56,190	50,071	6,384
2006	57,381	50,538	6,396
2007	58,061	51,043	6,368
2008	58,543	51,722	6,359
2009	58,880	52,228	6,350
2010	59,255	52,694	6,349
2011	59,611	53,178	6,344
2012	59,971	53,750	6,325
2013	60,346	54,094	6,305
2014	60,758	54,538	6,292
2015	61,856	55,572	6,348
2016	62,996	56,726	6,405
2017	64,024	57,669	6,462
2018	65,107	58,733	6,519
2019	66,251	59,826	6,575
2020	67,419	60,923	6,633
2021	68,608	62,031	6,691
2022	69,817	63,148	6,749
2023	71,048	64,275	6,808
2024	72,301	65,414	6,869
2025	73,576	66,563	6,931

Figure A - 6: Low Energy Forecast

Low Demand Forecast (MW)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	12,426	10,545	889
2006	12,638	10,746	885
2007	12,779	10,946	882
2008	12,878	11,161	881
2009	12,966	11,371	879
2010	13,055	11,574	881
2011	13,136	11,777	880
2012	13,227	11,973	877
2013	13,332	12,164	875
2014	13,445	12,352	874
2015	13,696	12,691	881
2016	13,955	13,035	889
2017	14,128	13,384	897
2018	14,308	13,738	907
2019	14,497	14,104	914
2020	14,687	14,463	923
2021	14,878	14,825	932
2022	15,073	15,189	939
2023	15,270	15,555	948
2024	15,470	15,922	957
2025	15,672	16,292	965

Appendix B – Generation Capability Tables

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Figure B - 1: ITC Resources

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Detroit Edison Co.	Combined Cycle (existing)	Dearborn Industrial Generation LLC:CC1	760.00
Detroit Edison Co.	CT Gas	Ann Arbor GT:1	3.20
Detroit Edison Co.	CT Gas	Belle River:GT1	75.00
Detroit Edison Co.	CT Gas	Belle River:GT2	75.00
Detroit Edison Co.	CT Gas	Belle River:GT3	75.00
Detroit Edison Co.	CT Gas	Delray:11-1	63.00
Detroit Edison Co.	CT Gas	Delray:12-1	64.00
Detroit Edison Co.	CT Gas	DTE East China:GT10	76.00
Detroit Edison Co.	CT Gas	DTE East China:GT7	76.00
Detroit Edison Co.	CT Gas	DTE East China:GT8	76.00
Detroit Edison Co.	CT Gas	DTE East China:GT9	76.00
Detroit Edison Co.	CT Gas	Greenwood:GT1	75.00
Detroit Edison Co.	CT Gas	Greenwood:GT2	75.00
Detroit Edison Co.	CT Gas	Greenwood:GT3	75.00
Detroit Edison Co.	CT Gas	Hancock (DETED):1	11.00
Detroit Edison Co.	CT Gas	Hancock (DETED):2	18.00
Detroit Edison Co.	CT Gas	Hancock (DETED):3	17.00
Detroit Edison Co.	CT Gas	Hancock (DETED):4	17.00
Detroit Edison Co.	CT Gas	Hancock (DETED):5	38.00
Detroit Edison Co.	CT Gas	Hancock (DETED):6	40.00
Detroit Edison Co.	CT Gas	Hutzel Hospital:GTGS2	1.60
Detroit Edison Co.	CT Gas	Main Street (SEAW):GTGS6	6.13
Detroit Edison Co.	CT Gas	MPPA : Belle River	234.00
Detroit Edison Co.	CT Gas	Northeast (DETED):1	14.75
Detroit Edison Co.	CT Gas	Northeast (DETED):2	14.75
Detroit Edison Co.	CT Gas	Northeast (DETED):3	14.75
Detroit Edison Co.	CT Gas	Northeast (DETED):4	14.75
Detroit Edison Co.	CT Gas	Pine Street (SEAW):GTGS4	5.00
Detroit Edison Co.	CT Gas	Sumpter Township:GT1	72.25
Detroit Edison Co.	CT Gas	Sumpter Township:GT2	72.25
Detroit Edison Co.	CT Gas	Sumpter Township:GT3	72.25
Detroit Edison Co.	CT Gas	Sumpter Township:GT4	72.25
Detroit Edison Co.	CT Gas	Ubly:GTGS2	4.04
Detroit Edison Co.	CT Gas	Wayne County Airport:GTGS3	17.10
Detroit Edison Co.	CT Oil	Belle River:GTOL5	13.75
Detroit Edison Co.	CT Oil	Caro:GTOL6	8.55

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Detroit Edison Co.	CT Oil	Colfax (DETED):GTOL5	13.75
Detroit Edison Co.	CT Oil	Conners Creek:GTOL2	5.50
Detroit Edison Co.	CT Oil	Croswell Plant:3	1.21
Detroit Edison Co.	CT Oil	Croswell Plant:GTGS4	4.02
Detroit Edison Co.	CT Oil	Dayton (DETED):GTOL5	10.00
Detroit Edison Co.	CT Oil	Fermi:GTOL4	51.00
Detroit Edison Co.	CT Oil	Harbor Beach:GTOL2	4.00
Detroit Edison Co.	CT Oil	Michigan Automotive Research:1-8	0.00
Detroit Edison Co.	CT Oil	Mistersky:GT1	30.00
Detroit Edison Co.	CT Oil	Monroe (DETED):GTOL5	13.75
Detroit Edison Co.	CT Oil	Northeast (DETED):5	17.00
Detroit Edison Co.	CT Oil	Northeast (DETED):6	19.50
Detroit Edison Co.	CT Oil	Northeast (DETED):7	19.50
Detroit Edison Co.	CT Oil	Oliver:GTOL5	13.75
Detroit Edison Co.	CT Oil	Pine Street (SEAW):GTOL2	2.28
Detroit Edison Co.	CT Oil	Placid 12:GTOL5	13.75
Detroit Edison Co.	CT Oil	Putnam (DETED):GTOL5	13.75
Detroit Edison Co.	CT Oil	River Rouge:GTOL4	11.00
Detroit Edison Co.	CT Oil	Slocum:GTOL5	13.75
Detroit Edison Co.	CT Oil	St. Clair:11	19.00
Detroit Edison Co.	CT Oil	St. Clair:GTOL2	5.50
Detroit Edison Co.	CT Oil	Superior:GTOL4	52.00
Detroit Edison Co.	CT Oil	Ubly:GTOL5	4.51
Detroit Edison Co.	CT Oil	Wilmont:GTOL5	13.75
Detroit Edison Co.	Hydro Run-of-River	DETED Small Hydros:HYOP2	1.40
Detroit Edison Co.	Hydro Run-of-River	Ford Lake:HYOP1	0.85
Detroit Edison Co.	Hydro Run-of-River	French Landing Dam:HYOP1	1.80
Detroit Edison Co.	Interruptible Load	DETED Interruptible:1	0.00
Detroit Edison Co.	Landfill Gas	Ann Arbor Generating Station:1	1.60
Detroit Edison Co.	Landfill Gas	Arbor Hills Generating Facilit:CC	17.40
Detroit Edison Co.	Landfill Gas	Carleton Farms Generating Project:1	6.40
Detroit Edison Co.	Landfill Gas	EQ - Waste Energy Services Inc:GTGS4	1.40
Detroit Edison Co.	Landfill Gas	Lyon Generating Facility:GTGS7	4.50
Detroit Edison Co.	Landfill Gas	Pine Tree Acres:GTGS5	4.00
Detroit Edison Co.	Landfill Gas	Riverview Energy Systems:GTGS2	6.60
Detroit Edison Co.	Landfill Gas	Sumpter Energy Assoc.:GTGS10	12.00
Detroit Edison Co.	Nuclear (existing)	Fermi:2	1111.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Detroit Edison Co.	ST Coal	Belle River:ST1	509.00
Detroit Edison Co.	ST Coal	Belle River:ST2	517.00
Detroit Edison Co.	ST Coal	Harbor Beach:1	103.00
Detroit Edison Co.	ST Coal	Monroe (DETED):1	770.00
Detroit Edison Co.	ST Coal	Monroe (DETED):2	785.00
Detroit Edison Co.	ST Coal	Monroe (DETED):3	785.00
Detroit Edison Co.	ST Coal	Monroe (DETED):4	775.00
Detroit Edison Co.	ST Coal	NAO GM Pontiac Power Plant:1	28.94
Detroit Edison Co.	ST Coal	River Rouge:2	238.00
Detroit Edison Co.	ST Coal	River Rouge:3	272.00
Detroit Edison Co.	ST Coal	St. Clair:1	153.00
Detroit Edison Co.	ST Coal	St. Clair:2	162.00
Detroit Edison Co.	ST Coal	St. Clair:3	171.00
Detroit Edison Co.	ST Coal	St. Clair:4	158.00
Detroit Edison Co.	ST Coal	St. Clair:6	321.00
Detroit Edison Co.	ST Coal	St. Clair:7	450.00
Detroit Edison Co.	ST Coal	Trenton Channel:7	0.00
Detroit Edison Co.	ST Coal	Trenton Channel:8	210.00
Detroit Edison Co.	ST Coal	Trenton Channel:9	520.00
Detroit Edison Co.	ST Coal	Wyandotte (WYAN):7	30.00
Detroit Edison Co.	ST Coal	Wyandotte (WYAN):8	22.00
Detroit Edison Co.	ST Gas	Conners Creek:15	0.00
Detroit Edison Co.	ST Gas	Conners Creek:16	215.00
Detroit Edison Co.	ST Gas	River Rouge:1	234.00
Detroit Edison Co.	ST Gas	Wyandotte (WYAN):5	20.00
Detroit Edison Co.	ST Oil	Greater Detroit Resource Recov:GEN1	30.75
Detroit Edison Co.	ST Oil	Greenwood:1	785.00
Detroit Edison Co.	ST Oil	Mistersky:5	34.29
Detroit Edison Co.	ST Oil	Mistersky:6	38.96
Detroit Edison Co.	ST Oil	Mistersky:7	46.75
Detroit Edison Co.	ST Other	Refuse 2:1	20.00

Figure B - 2: METC Resources

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Combined Cycle (existing)	Ada Cogeneration Limited Partn:CC	29.40
Consumers Energy Co.	Combined Cycle (existing)	Covert:CC3	384.00
Consumers Energy Co.	Combined Cycle (existing)	Covert:CC4	384.00
Consumers Energy Co.	Combined Cycle (existing)	Covert:CC5	384.00
Consumers Energy Co.	Combined Cycle (existing)	Covert:CCGS3	48.00
Consumers Energy Co.	Combined Cycle (existing)	Jackson:CCA	280.00
Consumers Energy Co.	Combined Cycle (existing)	Jackson:CCB	280.00
Consumers Energy Co.	Combined Cycle (existing)	Michigan Power L.P.:CC	123.00
Consumers Energy Co.	Combined Cycle (existing)	Midland Cogeneration Venture (MCV):CC	1240.00
Consumers Energy Co.	Combined Cycle (existing)	Zeeland (MIR):CC1	532.00
Consumers Energy Co.	CT Gas	491 E. 48th Street:7	37.60
Consumers Energy Co.	CT Gas	491 E. 48th Street:8	37.60
Consumers Energy Co.	CT Gas	491 E. 48th Street:9	83.50
Consumers Energy Co.	CT Gas	B.E. Morrow:GTGS2	34.00
Consumers Energy Co.	CT Gas	Clinton (CLIN):6	2.00
Consumers Energy Co.	CT Gas	Coldwater:GTGS2	8.50
Consumers Energy Co.	CT Gas	Diesel Plant (GHLP):GTGS3	11.90
Consumers Energy Co.	CT Gas	Diesel Plant - STURGI:6	6.00
Consumers Energy Co.	CT Gas	Gaylord:GTGS5	85.00
Consumers Energy Co.	CT Gas	Grand Rapids East:1	0.00
Consumers Energy Co.	CT Gas	Hart:GTGS4	4.82

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	CT Gas	Hillsdale:GTGS4	17.70
Consumers Energy Co.	CT Gas	Kalamazoo River Generating Station:GT	68.00
Consumers Energy Co.	CT Gas	Livingston Generating Station:1	42.90
Consumers Energy Co.	CT Gas	Livingston Generating Station:2	42.43
Consumers Energy Co.	CT Gas	Livingston Generating Station:3	42.43
Consumers Energy Co.	CT Gas	Livingston Generating Station:4	42.43
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT1	171.00
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT2	171.00
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT3	171.00
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT4	171.00
Consumers Energy Co.	CT Gas	Straits:1	21.00
Consumers Energy Co.	CT Gas	Thetford:1	37.00
Consumers Energy Co.	CT Gas	Thetford:2	37.00
Consumers Energy Co.	CT Gas	Thetford:3	37.00
Consumers Energy Co.	CT Gas	Thetford:4	37.00
Consumers Energy Co.	CT Gas	Thetford:GTGS5	86.00
Consumers Energy Co.	CT Gas	Weadock:A	17.00
Consumers Energy Co.	CT Gas	Zeeland (MIR):GT1	149.00
Consumers Energy Co.	CT Gas	Zeeland (MIR):GT2	149.00
Consumers Energy Co.	CT Gas	Zeeland (ZBPW):GTGS7	24.00
Consumers Energy Co.	CT Oil	Alma Modular:GTOL7	0.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	CT Oil	APG Four Mile Substation (PPA):GTOL1	18.25
Consumers Energy Co.	CT Oil	APG Long Lake Road (PPA):GTOL1	9.00
Consumers Energy Co.	CT Oil	APG Michigan Limestone (PPA):GTOL1	18.25
Consumers Energy Co.	CT Oil	APG Rockport (PPA):GTOL1	9.13
Consumers Energy Co.	CT Oil	Campbell (CEC):A	17.00
Consumers Energy Co.	CT Oil	Chelsea Modular:GTOL3	0.00
Consumers Energy Co.	CT Oil	Clinton (CLIN):GTOL5	2.20
Consumers Energy Co.	CT Oil	Coldwater Modular:GTOL10	0.00
Consumers Energy Co.	CT Oil	Coldwater:GTOL2	3.50
Consumers Energy Co.	CT Oil	Diesel Plant (GHLP):5	3.00
Consumers Energy Co.	CT Oil	Diesel Plant (GHLP):7	5.10
Consumers Energy Co.	CT Oil	Diesel Plant - STURGI:GTOL4	2.80
Consumers Energy Co.	CT Oil	Frank Jenkins:5	1.70
Consumers Energy Co.	CT Oil	Frank Jenkins:GTOL2	0.38
Consumers Energy Co.	CT Oil	Henry Station:GTOL2	15.40
Consumers Energy Co.	CT Oil	Hillsdale:2	1.90
Consumers Energy Co.	CT Oil	Marshall (MCWEW):GTGS5	10.70
Consumers Energy Co.	CT Oil	Saginaw Station:GTOL2	12.60
Consumers Energy Co.	CT Oil	Sixth Street Mi:1	22.00
Consumers Energy Co.	CT Oil	St. Louis (STLO):GTGS2	2.50
Consumers Energy Co.	CT Oil	St. Louis (STLO):GTOL2	1.70

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	CT Oil	Whiting (CEC):A	17.00
Consumers Energy Co.	CT Oil	Zilwaukee:1-12	0.00
Consumers Energy Co.	CT Oil	Zilwaukee:13-33	0.00
Consumers Energy Co.	Hydro Run-of-River	Ada Dam:HYOP1	1.40
Consumers Energy Co.	Hydro Run-of-River	Alcona:HYOP2	8.00
Consumers Energy Co.	Hydro Run-of-River	Allegan Dam:HYOP3	2.50
Consumers Energy Co.	Hydro Run-of-River	Beaverton (PPA):HYOP1	0.50
Consumers Energy Co.	Hydro Run-of-River	Black River (PPA):HYOP1	0.84
Consumers Energy Co.	Hydro Run-of-River	C.W. Tippy:HYOP3	21.00
Consumers Energy Co.	Hydro Run-of-River	Cascade Dam:HYOP1	1.40
Consumers Energy Co.	Hydro Run-of-River	CEC Small Hydros:HYOP20	0.00
Consumers Energy Co.	Hydro Run-of-River	Cheboygan:HYOP1	0.00
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (Hubbardston PPA):HYOP1	0.22
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (Irving PPA):HYOP1	0.24
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (LaBarge PPA):HYOP1	0.70
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (Middleville PPA):HYOP1	0.20
Consumers Energy Co.	Hydro Run-of-River	Cooke:HYOP1	1.50
Consumers Energy Co.	Hydro Run-of-River	Cooke:HYOP2	3.00
Consumers Energy Co.	Hydro Run-of-River	Cooke:HYOP3	3.00
Consumers Energy Co.	Hydro Run-of-River	Croton:HYOP4	8.40
Consumers Energy Co.	Hydro Run-of-River	Edenville:HYOP2	11.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Hydro Run-of-River	Five Channels:HYOP1	3.20
Consumers Energy Co.	Hydro Run-of-River	Five Channels:HYOP2	3.20
Consumers Energy Co.	Hydro Run-of-River	Foote:HYOP1	3.30
Consumers Energy Co.	Hydro Run-of-River	Foote:HYOP2	3.30
Consumers Energy Co.	Hydro Run-of-River	Foote:HYOP3	3.30
Consumers Energy Co.	Hydro Run-of-River	Four Mile Dam:HYOP3	1.80
Consumers Energy Co.	Hydro Run-of-River	Grenfell Hydro (PPA):HYOP1	0.30
Consumers Energy Co.	Hydro Run-of-River	Hodenpyl:HYOP1	9.20
Consumers Energy Co.	Hydro Run-of-River	Hodenpyl:HYOP2	9.20
Consumers Energy Co.	Hydro Run-of-River	Hydro Plant - STURGI:HYOP4	1.50
Consumers Energy Co.	Hydro Run-of-River	Loud:HYOP1	2.20
Consumers Energy Co.	Hydro Run-of-River	Loud:HYOP2	2.20
Consumers Energy Co.	Hydro Run-of-River	Michiana Hydro (PPA):HYOP1	0.08
Consumers Energy Co.	Hydro Run-of-River	Mio:HYOP1	2.20
Consumers Energy Co.	Hydro Run-of-River	Mio:HYOP2	2.20
Consumers Energy Co.	Hydro Run-of-River	Ninth Street Dam:HYOP3	1.20
Consumers Energy Co.	Hydro Run-of-River	Norway Point Hydropower Projec:HYOP2	4.00
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP1	1.50
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP2	1.50
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP3	1.50
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP4	1.50

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Hydro Run-of-River	Sanford:HYOP3	0.00
Consumers Energy Co.	Hydro Run-of-River	Secord:HYOP1	0.00
Consumers Energy Co.	Hydro Run-of-River	Smallwood:HYOP1	0.00
Consumers Energy Co.	Hydro Run-of-River	Webber:HYOP1	2.30
Consumers Energy Co.	Hydro Run-of-River	Webber:HYOP2	1.00
Consumers Energy Co.	Hydro Run-of-River	Whites Bridge Hydro (PPA):HYOP1	0.82
Consumers Energy Co.	Hydro Storage	Hardy:HYOP1	10.80
Consumers Energy Co.	Hydro Storage	Hardy:HYOP2	10.80
Consumers Energy Co.	Hydro Storage	Hardy:HYOP3	10.80
Consumers Energy Co.	Interruptible Load	CEC Interruptible:1	0.00
Consumers Energy Co.	Landfill Gas	Adrian Energy Assoc. LLC:GTGS3	2.50
Consumers Energy Co.	Landfill Gas	Brent Run Generating Station:GTGS2	1.60
Consumers Energy Co.	Landfill Gas	C & C Generating Facility:GTGS3	2.75
Consumers Energy Co.	Landfill Gas	Grand Blanc Generating Station:GTGS3	3.81
Consumers Energy Co.	Landfill Gas	Granger Electric Generating Station I:GTGS4	3.04
Consumers Energy Co.	Landfill Gas	Granger Electric Generating Station II:GTGS5	3.79
Consumers Energy Co.	Landfill Gas	Ottawa Generating Station:GTGS6	4.57
Consumers Energy Co.	Landfill Gas	Peoples Generating Station:1	3.06
Consumers Energy Co.	Landfill Gas	Seymour Road Generating Statio:GTGS2	0.75
Consumers Energy Co.	Landfill Gas	Venice Resources Gas Recovery:GTGS2	1.50
Consumers Energy Co.	Nuclear (existing)	Palisades (CEC):1	803.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Pumped Storage Hydro	Ludington:PSOP6	1871.70
Consumers Energy Co.	ST Coal	Campbell (CEC):1	260.00
Consumers Energy Co.	ST Coal	Campbell (CEC):2	360.00
Consumers Energy Co.	ST Coal	Campbell (CEC):3	820.00
Consumers Energy Co.	ST Coal	Cobb:4	160.00
Consumers Energy Co.	ST Coal	Cobb:5	160.00
Consumers Energy Co.	ST Coal	Endicott:1	55.00
Consumers Energy Co.	ST Coal	James De Young:3	10.50
Consumers Energy Co.	ST Coal	James De Young:4	20.50
Consumers Energy Co.	ST Coal	James De Young:5	27.00
Consumers Energy Co.	ST Coal	Karn:1	255.00
Consumers Energy Co.	ST Coal	Karn:2	260.00
Consumers Energy Co.	ST Coal	S. D. Warren Co. #1 Muskeg:GEN5	0.00
Consumers Energy Co.	ST Coal	S. D. Warren Co. #1 Muskeg:STCL2	0.00
Consumers Energy Co.	ST Coal	TES Filer City Station:1	60.00
Consumers Energy Co.	ST Coal	Weadock:7	155.00
Consumers Energy Co.	ST Coal	Weadock:8	155.00
Consumers Energy Co.	ST Coal	Whiting (CEC):1	102.00
Consumers Energy Co.	ST Coal	Whiting (CEC):2	102.00
Consumers Energy Co.	ST Coal	Whiting (CEC):3	124.00
Consumers Energy Co.	ST Gas	Cobb:1	68.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	ST Gas	Cobb:2	61.00
Consumers Energy Co.	ST Gas	Cobb:3	52.00
Consumers Energy Co.	ST Gas	Karn:4	638.00
Consumers Energy Co.	ST Oil	Karn:3	638.00
Consumers Energy Co.	ST Oil	Recycled Board Division:STOH2	0.00
Consumers Energy Co.	ST Other	Cadillac Renewable Energy:1	34.00
Consumers Energy Co.	ST Other	Genesee Power Station:1	35.00
Consumers Energy Co.	ST Other	Grayling Generating Station:1	36.17
Consumers Energy Co.	ST Other	Hillman:1	16.00
Consumers Energy Co.	ST Other	Jackson County Resource Recove:1	0.00
Consumers Energy Co.	ST Other	Kent County Waste-to-Energy Fa:ST2	15.68
Consumers Energy Co.	ST Other	Lincoln Power Station:1	18.00
Consumers Energy Co.	ST Other	McBain Power Station:1	18.00
Consumers Energy Co.	Wind	Mackinaw City:WIOP5	1.80

Figure B - 3: Wolverine Resources

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

Figure B - 4: City Of Lansing Resources

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Lansing Board of Water & Light	Hydro Run-of-River	LBWL Small Hydros:HYOP2	1.06
Lansing Board of Water & Light	Hydro Run-of-River	Moores Park:HYOP2	1.00
Lansing Board of Water & Light	Interruptible Load	LBWL Interruptible:1	12.00
Lansing Board of Water & Light	ST Coal	Eckert:1	45.63
Lansing Board of Water & Light	ST Coal	Eckert:2	46.62
Lansing Board of Water & Light	ST Coal	Eckert:3	50.79
Lansing Board of Water & Light	ST Coal	Eckert:4	78.23
Lansing Board of Water & Light	ST Coal	Eckert:5	79.35
Lansing Board of Water & Light	ST Coal	Eckert:6	77.33
Lansing Board of Water & Light	ST Coal	Erickson:1	158.53

Figure B - 5: Unit Retirements

Plant Name	Unit #	Retire Year	Capacity MW
COBB	1	2013	68
COBB	2	2013	61
COBB	3	2015	52
MSTERSKY	5	2015	39
TRNTNCHN	8	2015	210
JMSDYUNG	3	2016	11
CNNRSCRK	16	2016	215
WHTNGCEC	1	2017	102
WHTNGCEC	2	2017	102
WHTNGCEC	3	2018	124
STCLAIR	1	2018	153
STCLAIR	2	2018	162
ECKERT	1	2019	46
STCLAIR	3	2019	171
STCLAIR	4	2019	158
WEADOCK	7	2020	155
PRSQISLE	1	2020	25
COBB	4	2021	160
RVRROUGE	1	2021	242
COBB	5	2022	160
WEADOCK	8	2022	155
RVRROUGE	2	2022	247
WYNDTTWY	5	2022	22
ECKERT	2	2023	47
MSTERSKY	6	2023	47
RVRROUGE	3	2023	280
ESCANABA	2	2023	26
KARN	1	2024	255
KARN	2	2024	260

Appendix C – Results

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Figure C - 1: Base Case Results

Capacity Additions (Firm MW)	2005 to 2014	2005-2024
CT	1,280	3,040
CC	1,500	3,000
PC	4,000	11,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**17,040**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.16
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,640.9	$ 54,596.8
NPV Emission	$ 4,084.0	$ 7,642.3
NPV CO_2	$ 0.0	$ 0.0

Figure C - 2: Base Case Mix

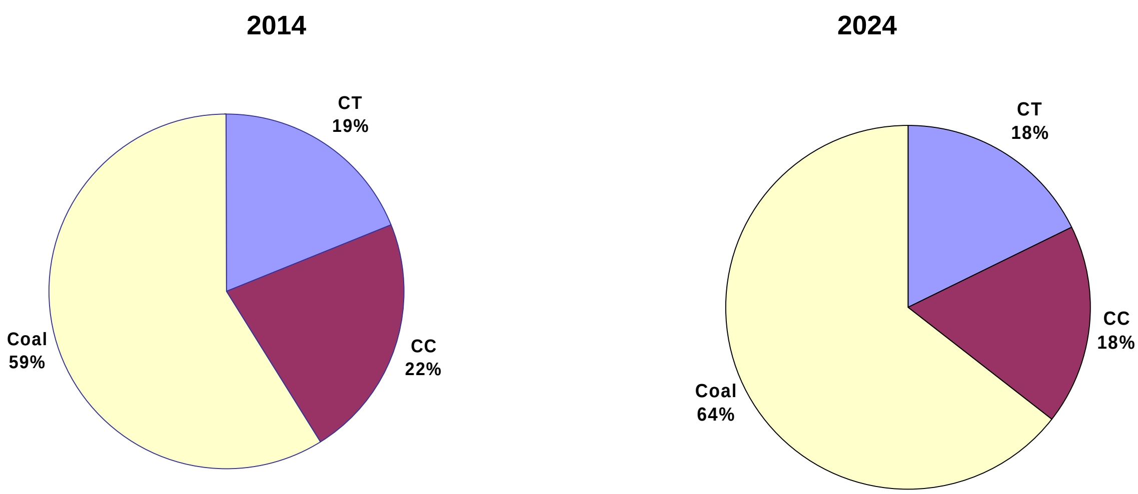


Figure C - 3: Base Case Plan

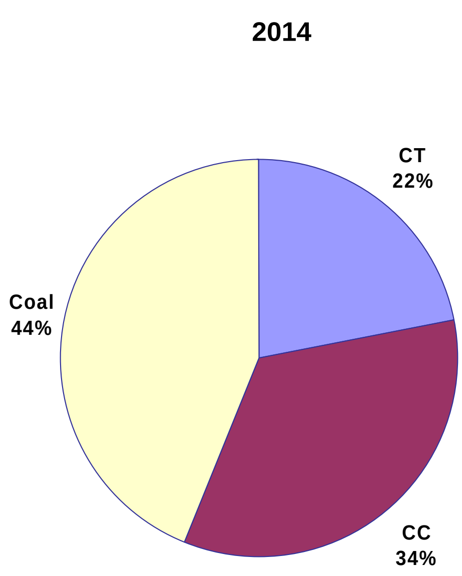
Base Case		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
7	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
5	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
10	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	-	1	1
CT - ITC	-	-	-	-	-	-	1	1	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	1	-
CC - ITC	-	-	-	-	-	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	-	1
COAL - ITC	1	1	1	-	1	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 4: Base Case/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,240	4,320
CC	3,500	4,500
PC	4,500	12,500
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**10,240**	**21,320**
Annual Demand Growth (%)	3.35	2.63
Reserve Margin (%)	15.14	15.00
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 32,282.9	$ 60,895.9
NPV Emission	$ 4,107.3	$ 7,771.3
NPV CO_2	$ 0.0	$ 0.0

Figure C - 5: Base Case/High Load Mix



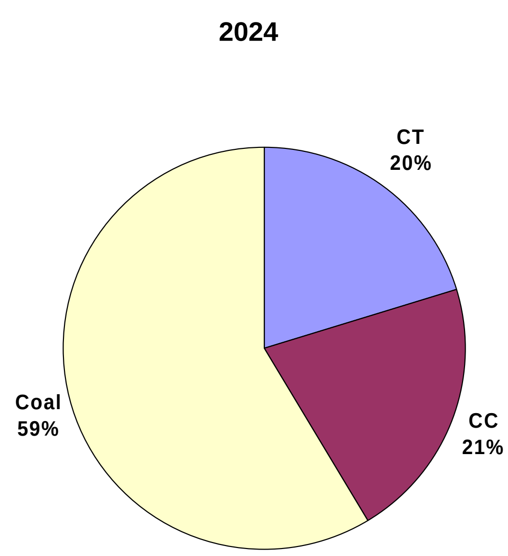


Figure C - 6: Base Case/High Load Plan

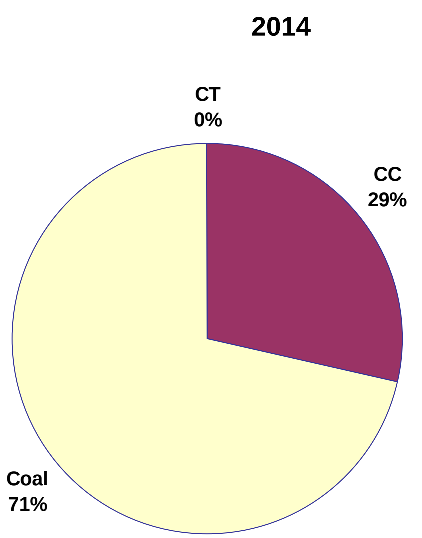
BC High Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	2	-	2	-	1	-	1	-
13	CT - ITC	-	-	2	2	-	2	-	-	1	-
2	CT - ATC2	-	-	-	-	-	-	-	-	1	-
3	CC - METC	-	-	-	-	-	1	-	-	-	1
6	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
13	COAL - METC	-	-	-	-	-	-	1	1	1	1
12	COAL - ITC	-	-	-	-	-	-	2	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	-	1	1	-	1	1	1	1
CT - ITC	-	-	-	1	1	1	1	1	1	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	1	1	1	1	1	1	1	-
COAL - ITC	1	1	1	-	1	1	-	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 7: Base Case/Low Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	0	1,280
CC	1,000	2,000
PC	2,500	9,500
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**3,500**	**12,780**
Annual Demand Growth (%)	1.30	1.66
Reserve Margin (%)	16.40	15.42
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 27,146.3	$ 48,707.3
NPV Emission	$4,046.1	$ 7,529.5
NPV CO_2	$ 0.0	$ 0.0

Figure C - 8: Base Case/Low Load Mix



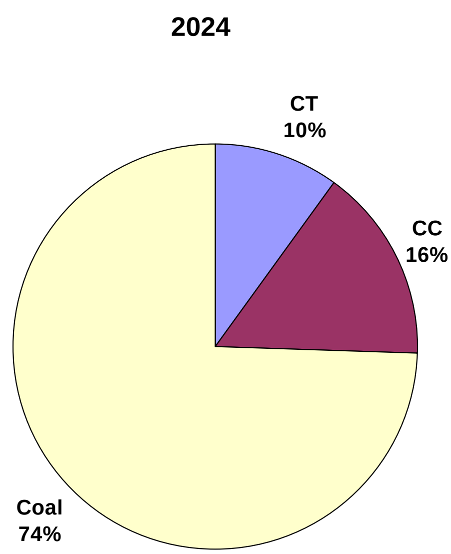


Figure C - 9: Base Case/Low Load Plan

BC Low Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	-	-	-	-	-	-	-	-
1	CT - ITC	-	-	-	-	-	-	-	-	-	-
0	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
9	COAL - METC	-	-	-	-	-	-	1	-	1	-
10	COAL - ITC	-	-	-	-	-	-	-	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	1	-	1	1	1	1
CT - ITC	-	-	-	1	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	1	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	-	-	1	1	1	1	1	-
COAL - ITC	-	1	1	1	1	1	-	1	-	1
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 10: Base Case/High Gas Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	2,880
CC	1,500	2,000
PC	4,000	12,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**16,880**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.03
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,794.9	$ 56,282.2
NPV Emission	$4,049.5	$ 7,588.1
NPV CO_2	$ 0.0	$ 0.0

Figure C - 11: Base Case/High Gas Mix

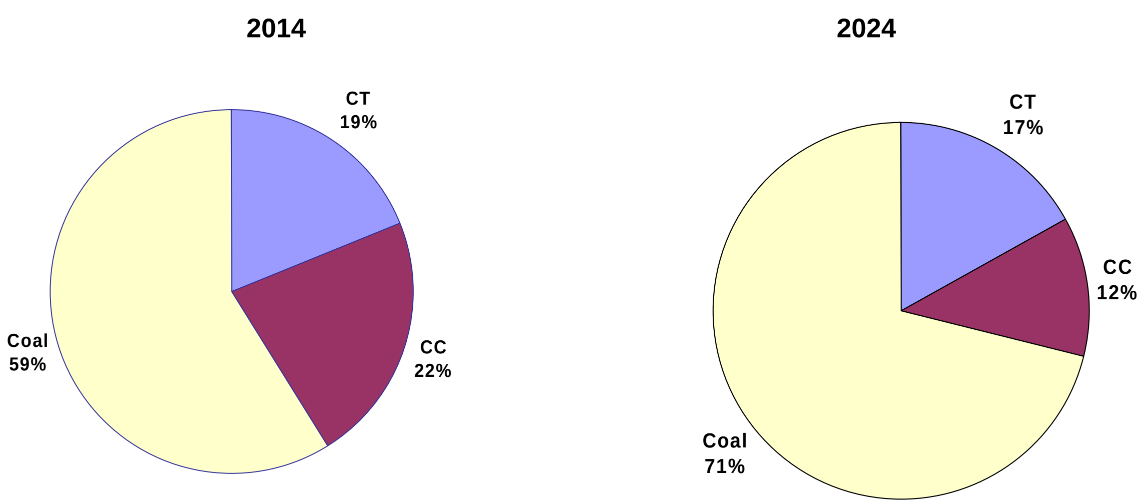


Figure C - 12: Base Case/High Gas Plan

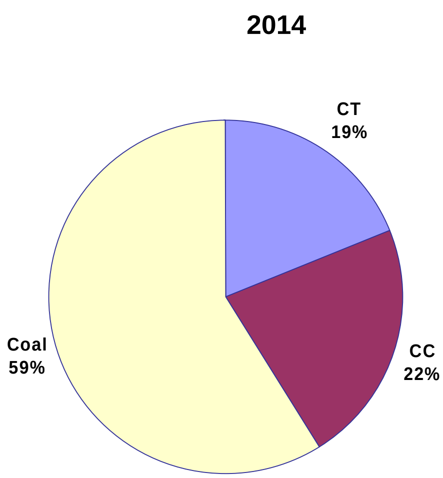
High Import		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
6	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
4	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
12	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	1	1	-
CT - ITC	-	-	-	-	-	-	1	-	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	-	1	1	1
COAL - ITC	1	1	1	-	1	1	1	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 13: Base Case/High Import Results

Capacity Additions (Firm MW)	2005 to 2014	2004 to 2024
CT	1,280	2,400
CC	1,500	1,500
PC	4,000	13,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**16,900**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.38
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,608.2	$ 54,238.5
NPV Emission	$ 4,089.3	$ 7,739.8
NPV CO_2	$ 0.0	$ 0.0

Figure C - 14: Base Case/High Import Mix



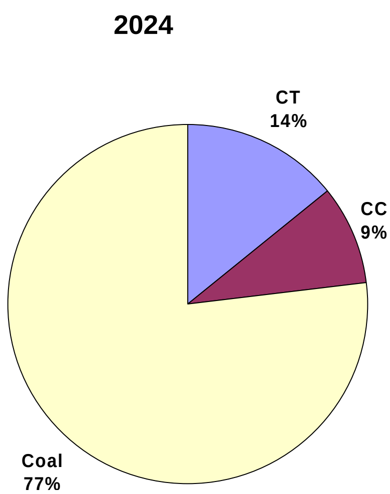


Figure C - 15: Base Case/High Import Plan

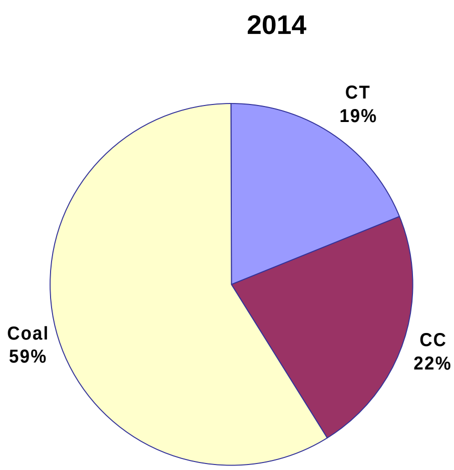
High Import		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	-	1	2	1	-	-	-	-
7	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
13	COAL - METC	-	-	-	-	-	-	1	1	1	1
13	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	-	-	-	1	-	1	-
CT - ITC	-	-	-	-	-	-	1	-	1	1
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	1	1
COAL - ITC	1	1	1	1	1	1	-	1	1	1
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 16: Base Case/Low Import Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	2,880
CC	1,500	2,000
PC	4,000	12,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**16,880**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.03
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,740.4	$ 54,870.9
NPV Emission	$ 4,070.6	$ 7,405.5
NPV CO_2	$ 0.0	$ 0.0

Figure C - 17: Base Case/Low Import Mix



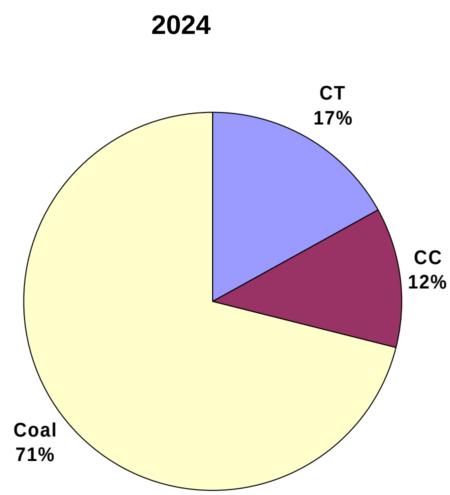


Figure C - 18: Base Case/Low Import Plan

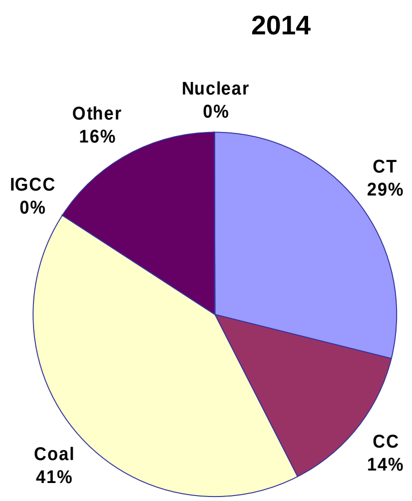
	BC Low Import	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
6	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
4	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
12	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	1	1	-
CT - ITC	-	-	-	-	-	-	1	-	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	-	1	1	1
COAL - ITC	1	1	1	-	1	1	1	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 19: Emissions Case

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,080	2,720
CC	1,000	1,000
PC	3,000	4,500
Nuclear	0	8,000
IGCC-Seq	0	0
Other	600	600
TOTAL	**6,680**	**16,820**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.19	15.03
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 33,543.9	$ 66,002.9
NPV Emission	$ 7,851.0	$ 20,195.6
NPV CO_2	$ 3,724.5	$ 12,751.3

Figure C - 20: Emission Case Mix



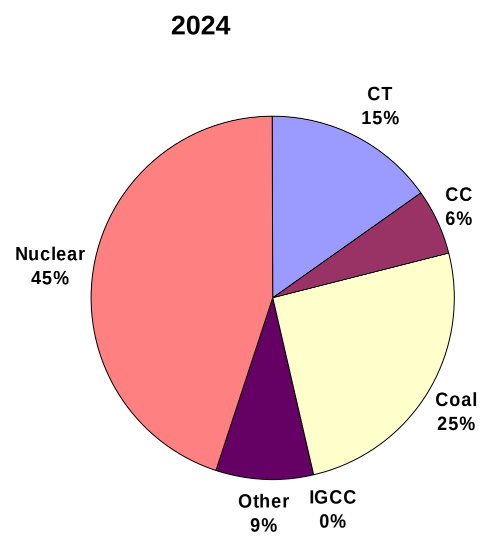


Figure C - 21: Emissions Case Plan

Emissions Case		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
9	CT - METC	-	-	-	2	1	2	-	1	-	1
7	CT - ITC	-	-	1	2	1	1	-	-	-	1
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
4	COAL - METC	-	-	-	-	-	-	1	-	1	-
5	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
4	NUC - METC	-	-	-	-	-	-	-	-	-	-
4	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	-	-	-	-	-	-	1
CT - ITC	-	1	-	-	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	-	-	-	-	-	-	-	-
COAL - ITC	1	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	1	1	-	1	-	1	-
NUC - ITC	-	-	1	-	1	-	-	1	1	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Figure C - 22: Emissions Case/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,080	2,720
CC	3,000	3,000
PC	4,500	6,000
Nuclear	0	9,000
IGCC-Seq	0	0
Other	600	600
TOTAL	**10,180**	**21,320**
Annual Demand Growth (%)	3.35	2.63
Reserve Margin (%)	15.31	15.87
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 38,373.4	$ 77,407.4
NPV Emission	$ 8,491.7	$ 22,443.2
NPV CO_2	$ 4,160.9	$ 14,575.1

Figure C - 23: Emissions Case/High Load Mix

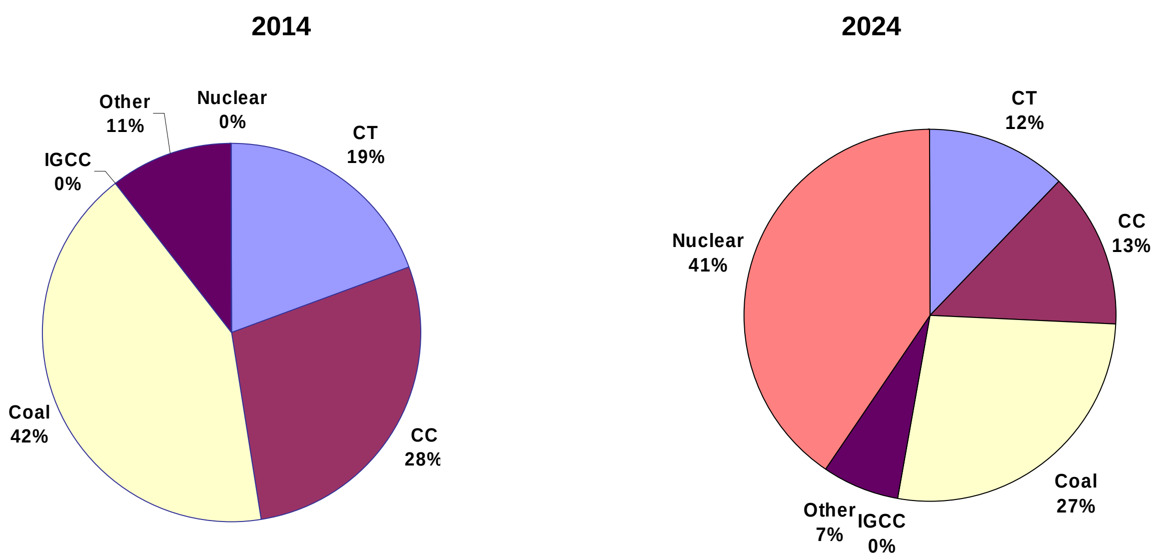


Figure C - 24: Emissions Case/High Load Plan

Emissions High Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
6	CT - METC	-	-	1	-	1	-	1	1	-	1
10	CT - ITC	-	-	2	1	1	1	1	1	-	1
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	1	-	-	-	-
5	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
7	COAL - METC	-	-	-	-	-	-	1	1	2	1
5	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
5	NUC - METC	-	-	-	-	-	-	-	-	-	-
4	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	-	-	-	-	-	-	-	-	-
CT - ITC	1	1	-	-	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	-	-	-	-	-	-	-	-
COAL - ITC	-	1	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	1	1	-	1	-	1	1
NUC - ITC	-	-	1	-	1	1	-	1	-	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Figure C - 25: Emissions Case/High Gas Results

Capacity Additions (Firm MW)	2004 to 2014	2004 to 2024
CT	2,080	2,560
CC	1,000	1,000
PC	3,000	4,500
Nuclear	0	9,000
IGCC-Seq	0	0
Other	600	600
TOTAL	**6,680**	**17,660**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.19	17.55
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 34, 737.7	$ 67,779.7
NPV Emission	$ 7,747.5	$ 19,925.8
NPV CO_2	$ 3,652.7	$ 12,525.2

Figure C - 26: Emissions Case/High Gas Mix

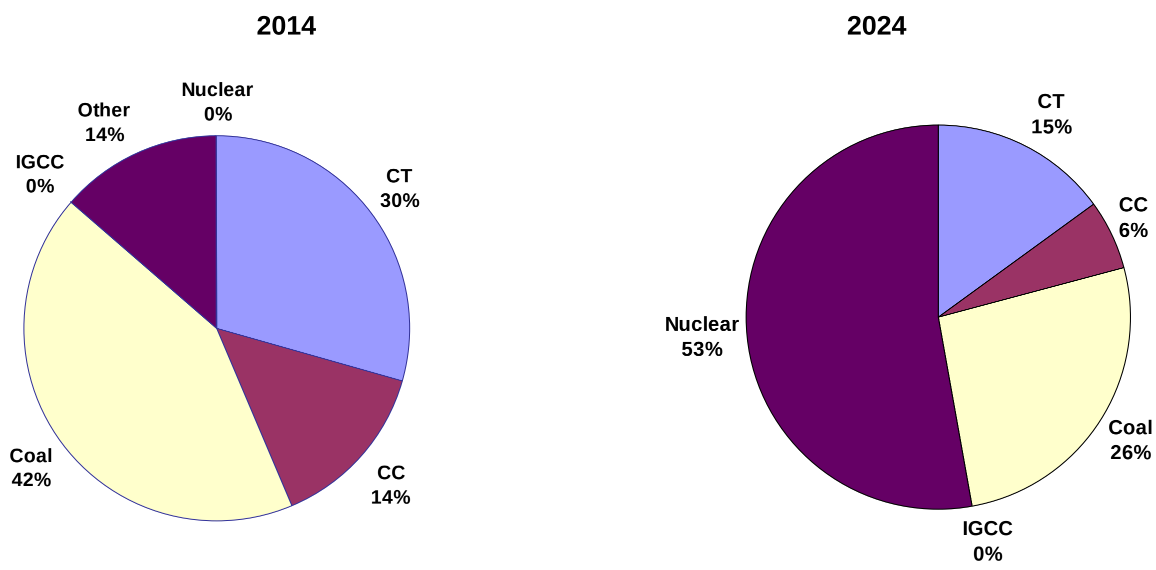


Figure C - 27: Emissions Case/High Gas Plan

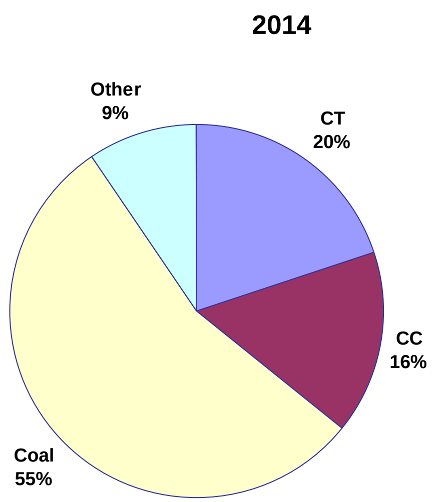
Emissions High Gas		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	-	2	1	2	-	-	-	1
8	CT - ITC	-	-	1	2	1	1	-	-	1	1
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
4	COAL - METC	-	-	-	-	-	-	1	1	1	-
5	COAL - ITC	-	-	-	-	-	-	1	1	-	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
5	NUC - METC	-	-	-	-	-	-	-	-	-	-
4	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	-	-	-	-	-	-	-
CT - ITC	-	1	-	-	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	-	-	-	-	-	-	-	-
COAL - ITC	1	1	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	1	-	1	-	1	-	1	1
NUC - ITC	-	-	1	-	-	1	-	1	1	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Figure C - 28: Energy Efficiency Case

Capacity Additions (Firm MW)	**2005 to 2014**	**2005 to 2024**
CT	1,280	3,040
CC	1,000	2,500
PC	3,500	10,000
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	**6,012**	**15,799**
Annual Demand Growth (%)	2.15	2.00
Reserve Margin (%)	15.34	15.07
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,802.9	$ 54,066.4
NPV Emission	$ 4,054.4	$ 7,509.6
NPV CO_2	$ 0.0	$ 0.0

Figure C - 29: Energy Efficiency Mix



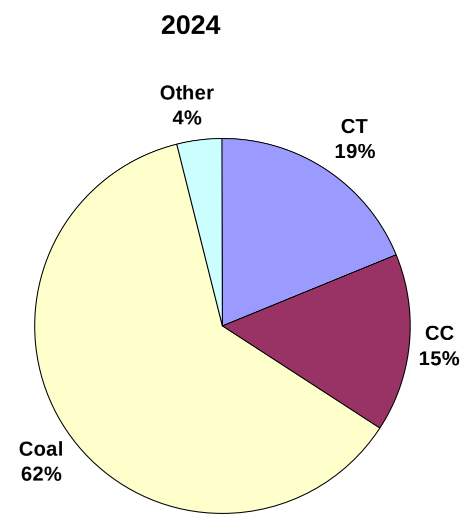


Figure C - 30: Energy Efficiency Plan

Conservaton		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
8	CT - METC	-	-	-	-	2	2	-	-	-	-
10	CT - ITC	-	-	-	1	2	1	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
4	CC - ITC	-	-	-	1	-	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
11	COAL - METC	-	-	-	-	-	-	1	1	-	1
9	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	-	-	1	-	1	-
CT - ITC	1	-	1	1	-	-	1	-	1	1
CT - ATC2	-	-	-	-	-	-	-	-	1	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	1	-
COAL - ITC	1	1	-	-	1	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 31: Energy Efficiency/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,440	2,880
CC	3,000	4,500
PC	5,000	12,500
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	9,672	20,139
Annual Demand Growth (%)	3.15	2.47
Reserve Margin (%)	15.58	15.34
Plan Costs (2005 $ million)		
NPV Utility Cost	$34,422.9	$ 60,335.7
NPV Emission	$ 4,092.3	$ 7,611.2
NPV CO_2	$ 0.0	$ 0.0

Figure C - 32: Energy efficiency/High Load Mix

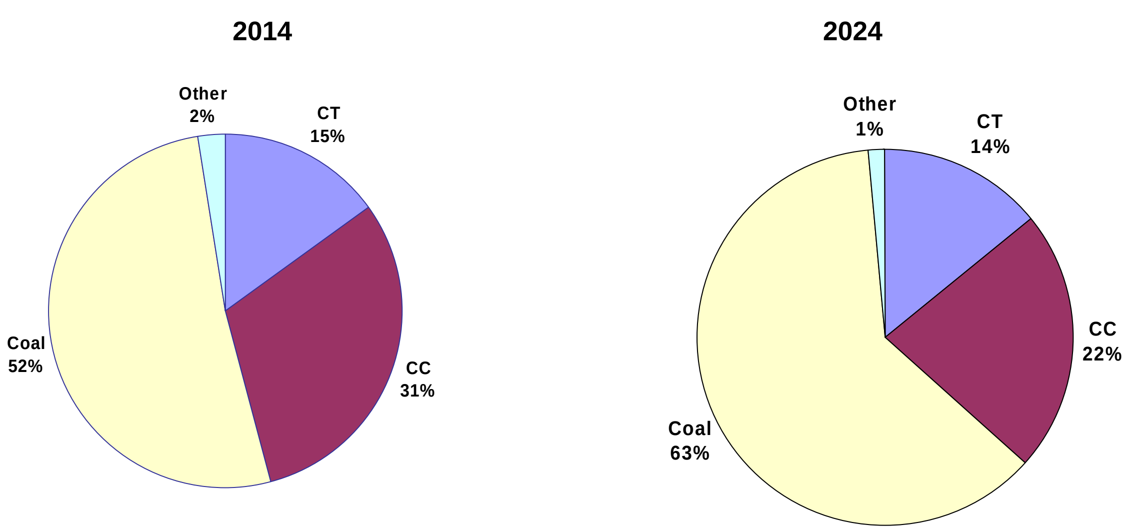


Figure C - 33: Energy Efficiency/High Load Plan

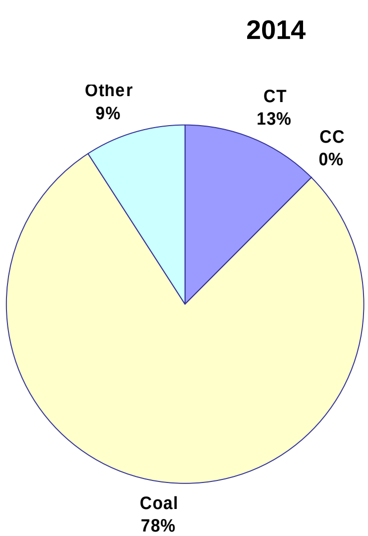
	Cons High Load	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	1	-	1	-	-	-	1	-
9	CT - ITC	-	-	1	1	1	1	-	1	-	-
2	CT - ATC2	-	-	-	-	-	-	-	-	1	-
2	CC - METC	-	-	-	-	-	1	-	-	-	-
7	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
14	COAL - METC	-	-	-	-	-	-	2	1	1	1
11	COAL - ITC	-	-	-	-	-	-	1	1	1	2
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	-	-	1	-	-	-	-	1	1
CT - ITC	-	-	-	1	-	-	-	1	1	1
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	1	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	1	1	1	1	1	1	1	-
COAL - ITC	-	1	1	-	1	1	-	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 34: Energy Efficiency/Low Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	320	1,280
CC	0	1,500
PC	2,000	8,500
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	**2,552**	**11,539**
Annual Demand Growth (%)	1.05	1.47
Reserve Margin (%)	15.18	15.33
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 27,317.70	$ 48,156.2
NPV Emission	$ 3,990.4	$ 7,359.9
NPV CO_2	$ 0.0	$ 0.0

Figure C - 35: Energy Efficiency/Low Load Mix



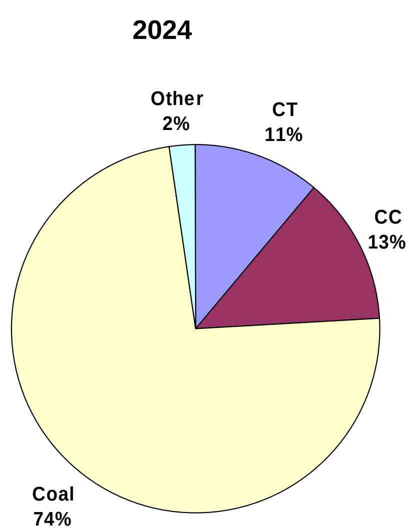


Figure C - 36: Energy Efficiency/Low Load Plan

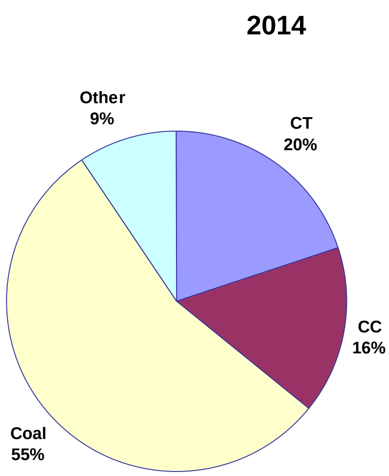
Cons Low Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
5	CT - METC	-	-	-	-	-	1	-	-	-	-
3	CT - ITC	-	-	-	-	-	1	-	-	-	-
0	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	-	-	-	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
9	COAL - METC	-	-	-	-	-	-	-	1	-	-
8	COAL - ITC	-	-	-	-	-	-	1	-	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	-	-	1	-	1	-
CT - ITC	-	-	1	-	-	-	-	-	1	-
CT - ATC2	-	-	-	-	-	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	1	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	-	1	1	1	1	1	1	1
COAL - ITC	1	1	1	-	-	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 37: Energy Efficiency/High Gas Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	3,040
CC	1,000	2,000
PC	3,500	10,500
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	**6,012**	**15,799**
Annual Demand Growth (%)	2.15	2.00
Reserve Margin (%)	15.34	15.22
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,873.8	$ 55,639.9
NPV Emission	$ 4,023.7	$ 7,452.9
NPV CO_2	$ 0.0	$ 0.0

Figure C - 38: Energy Efficiency/High Gas Mix



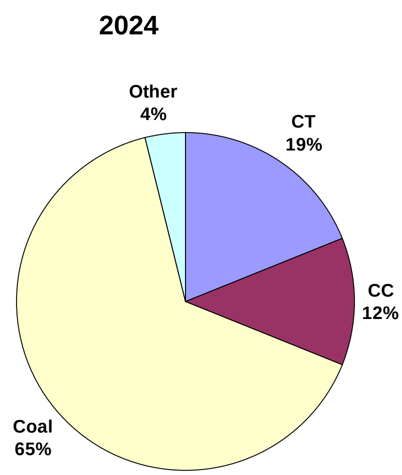


Figure C - 39: Energy Efficiency/High Gas Plan

Cons High Fuel		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
8	CT - METC	-	-	-	-	2	2	-	-	-	-
10	CT - ITC	-	-	-	1	2	1	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	1	-	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
11	COAL - METC	-	-	-	-	-	-	1	1	-	1
10	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	-	-	1	-	1	-
CT - ITC	-	1	1	1	-	-	1	-	1	1
CT - ATC2	-	-	-	-	-	-	-	-	1	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	1	1	1	1	1	1	1	-
COAL - ITC	1	1	-	-	1	1	-	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 40: Non-Traditional Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,760	3,520
CC	1,000	1,000
PC	0	0
Nuclear	0	0
IGCC-Seq	3,330	11,550
Other	779	1,035
TOTAL	**6,839**	**17,105**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.86	15.57
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,368.9	$ 57,477.8
NPV Emission	$ 4,040.4	$ 7,444.1
NPV CO_2	$ 0.0	$ 0.0

Figure C - 41: Non-Traditional Mix

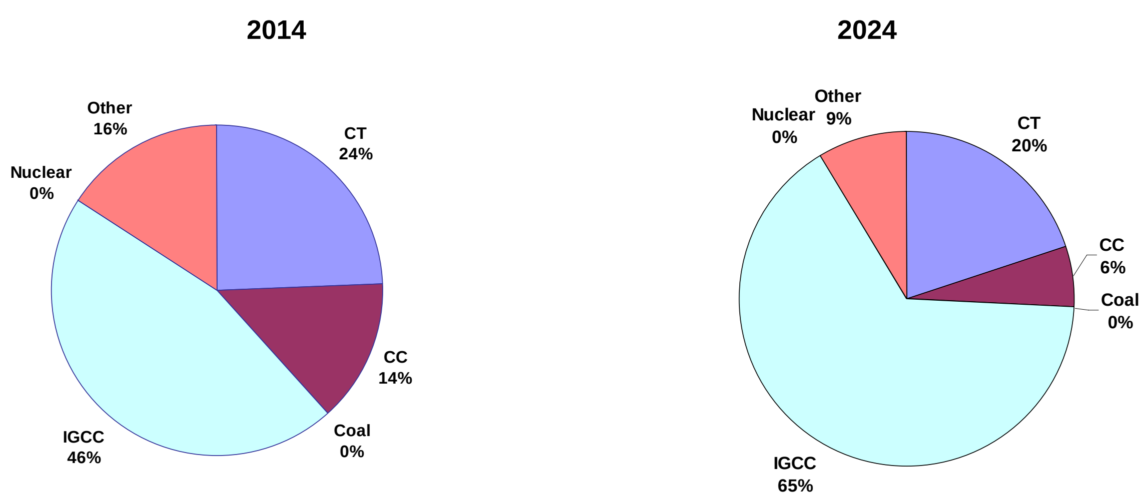


Figure C - 42: Non-Traditional Plan

NonTraditional		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	-	1	2	1	1	-	1	-
9	CT - ITC	-	-	1	2	-	1	1	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
10	IGCC - METC	-	-	-	-	-	-	-	1	-	1
11	IGCC - ITC	-	-	-	-	-	-	1	1	1	1

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	1	1	1	-	-	1	-	1	-
CT - ITC	-	1	1	1	-	-	1	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	1	1	-	1	1	1	1	1	1
IGCC - ITC	1	-	-	1	1	1	-	1	1	1

Figure C - 43: Non-Traditional/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,080	4,160
CC	3,000	3,000
PC	0	0
Nuclear	0	0
IGCC-Seq	4,400	13,200
Other	779	1,035
TOTAL	**10,259**	**21,395**
Annual Demand Growth (%)	3.35	2.63
Reserve Margin (%)	15.10	15.28
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 34,728.5	$ 67,023.5
NPV Emission	$ 4,235.3	$ 7,862.3
NPV CO_2	$ 0.0	$ 0.0

Figure C - 44: Non-Traditional/High Load Mix

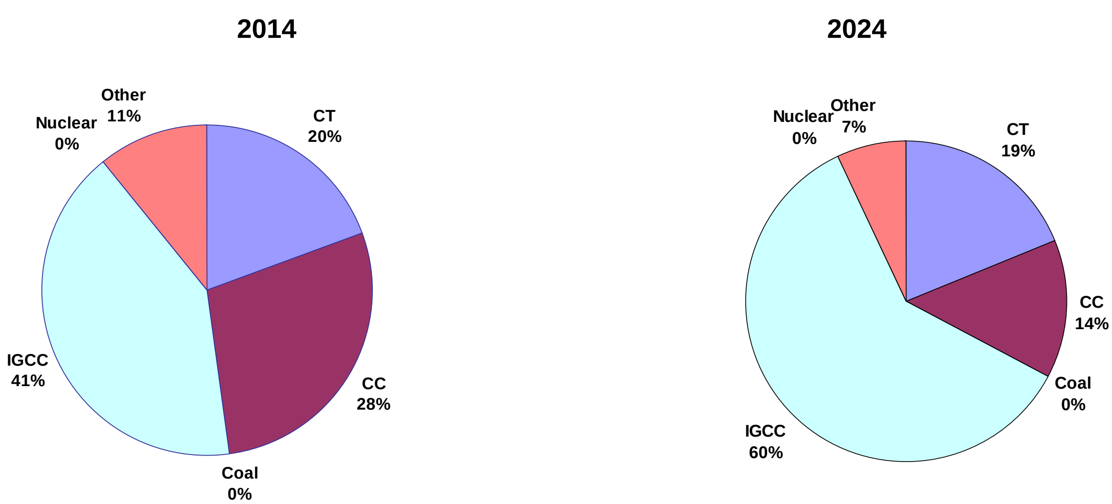


Figure C - 45: Non-Traditional/High Load Plan

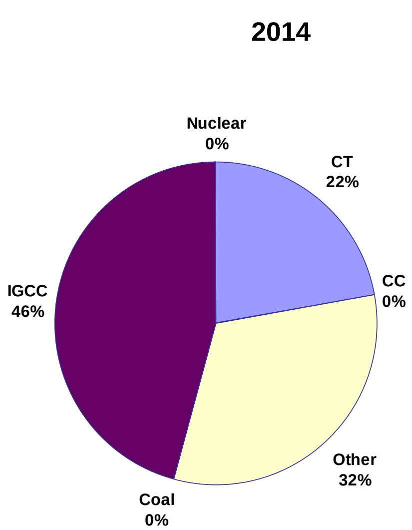
NonTrad High Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	-	-	1	-	1	1	1	1
12	CT - ITC	-	-	2	1	1	1	-	-	1	1
2	CT - ATC2	-	-	-	-	-	-	-	-	1	-
1	CC - METC	-	-	-	-	-	1	-	-	-	-
5	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
13	IGCC - METC	-	-	-	-	-	-	1	1	1	1
11	IGCC - ITC	-	-	-	-	-	-	1	1	1	1

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	1	1	1	-	-	1	-	1	1
CT - ITC	1	-	1	1	-	-	1	1	-	-
CT - ATC2	-	-	-	-	-	-	-	1	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	1	-	1	1	1	1	1	2	-	1
IGCC - ITC	-	2	-	-	1	1	-	-	2	1

Figure C - 46: Non-Traditional/Low Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	800	1,600
CC	0	0
PC	0	0
Nuclear	0	0
IGCC-Seq	1,650	9,900
Other	779	1,035
TOTAL	**3,249**	**12,535**
Annual Demand Growth (%)	1.30	1.66
Reserve Margin (%)	15.88	15.51
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,187.3	$53,523.5
NPV Emission	$ 4,143.6	$ 7,603.2
NPV CO_2	$ 0.0	$ 0.0

Figure C - 47: Non-Traditional/Low Load Mix



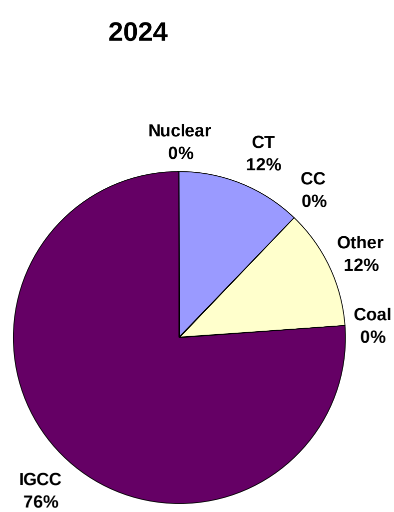


Figure C - 48: Non-Traditional/Low Load Plan

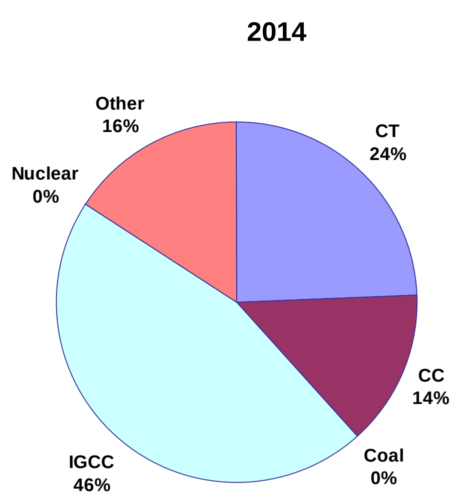
NonTrad Low Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
3	CT - METC	-	-	-	-	-	-	-	1	-	-
7	CT - ITC	-	-	-	-	1	1	-	1	-	1
0	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
0	CC - ITC	-	-	-	-	-	-	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
9	IGCC - METC	-	-	-	-	-	-	-	-	-	1
9	IGCC - ITC	-	-	-	-	-	-	1	-	1	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	-	1	-	-	-	-	-
CT - ITC	-	-	-	1	1	-	1	-	-	-
CT - ATC2	-	-	-	-	-	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	1	-	1	1	1	1	1	1	1
IGCC - ITC	1	1	1	-	-	1	-	1	1	1

Figure C - 49: Non-Traditional/High Gas Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,760	3,520
CC	1,000	1,000
PC	0	0
Nuclear	0	0
IGCC-Seq	3,300	11,550
Other	779	1,035
TOTAL	**6,839**	**17,105**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.86	15.57
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 31, 473.1	$ 59,149.8
NPV Emission	$ 4,010.0	$ 7,381.4
NPV CO_2	$ 0.0	$ 0.0

Figure C - 50: Non-Traditional/High Gas Mix



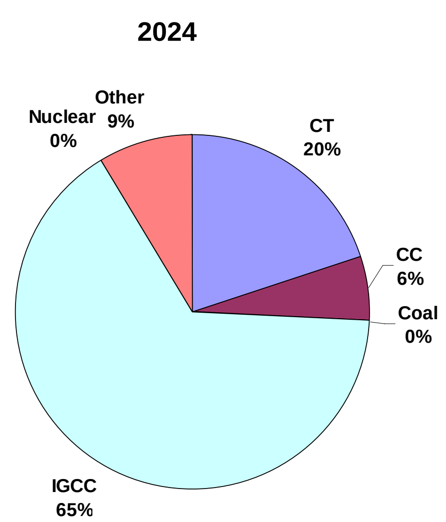


Figure C - 51: Non-Traditional/High Gas Plan

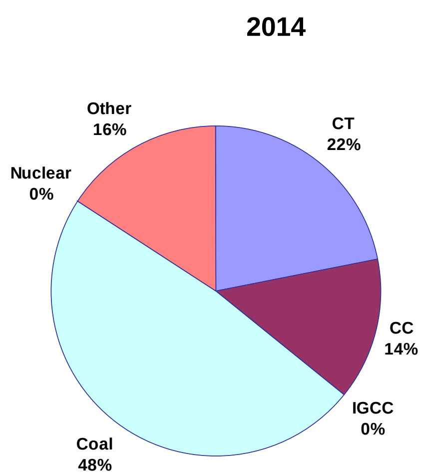
	NonTrad High Fuel	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	-	1	2	2	-	-	1	-
9	CT - ITC	-	-	1	2	-	-	-	1	1	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
10	IGCC - METC	-	-	-	-	-	-	1	-	-	1
11	IGCC - ITC	-	-	-	-	-	-	1	1	1	1

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	1	1	1	-	-	1	-	1	-
CT - ITC	-	1	1	1	-	-	1	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	1	1	-	1	1	1	1	1	1
IGCC - ITC	1	-	-	1	1	1	-	1	1	1

Figure C - 52: Non-Traditional with PC Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,600	3,360
CC	1,000	1,000
PC	3,500	11,500
Nuclear	0	0
IGCC-Seq	0	0
Other	779	1,035
TOTAL	**6,879**	**16,895**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	16.06	15.00
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,106.3	$ 55,864.4
NPV Emission	$ 4,064.2	$ 7,557.1
NPV CO_2	$ 0.0	$ 0.0

Figure C - 53: Non-Traditional with PC Mix



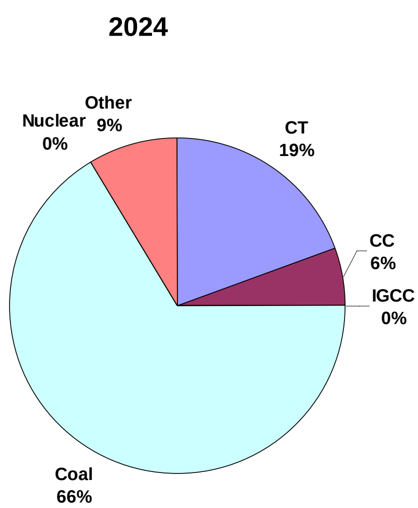


Figure C - 54: Non-Traditional with PC Plan

NonTrad with PC		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	2	-	1	-	-
9	CT - ITC	-	-	1	2	-	-	-	1	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
11	COAL - METC	-	-	-	-	-	-	1	-	1	1
12	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	-	1	-	1	-
CT - ITC	1	1	-	1	-	-	1	-	1	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	1	-	1	1	1	1	1	1
COAL - ITC	-	1	1	1	1	1	-	1	1	1
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Appendix D

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D.1 Strategist Model

Strategist, a computer software system developed by New Energy 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 chronological 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 is 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 to comprehensive pro forma financial results. The system includes full input summaries and detailed diagnostics

D.2 Supply Side Representation

The Generation and Fuel (GAF) 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:

- The GAF Module uses probabilistic production costing techniques to simulate the effects of forced outages.

- Most module calculations are performed seasonally, where seasons are defined by number of seasons and by number of days per season.
- Sales, purchases, and hydro generation are accounted for on a seasonal basis.
- The user can explicitly define an hour-by-hour schedule for a transaction or simply specify when the transaction tends to occur (during peak load hours, low load hours, or randomly) and the GAF will schedule the transaction appropriately.
- Thermal generating units are represented by capacity segments; 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.
- The dispatch of thermal units and economy energy may be performed on a seasonal or annual basis.
- Pumped hydro projects and direct load control programs are economically dispatched on a seasonal basis, based on marginal cost.
- Units are dispatched to conform to upper and lower limitations on fuel usage.
- Unit dispatch is performed on an 'as burned' or replacement cost of fuel basis.
- Unit, company and system emissions are calculated based on actual runtimes and fuel usage. Emissions allowances are 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 are calculated for emissions, emergency energy, and direct load control.
- Multicompany dispatch with interchange accounting for holding companies or power pool simulation is provided.
- Numerous diagnostic reports 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:

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 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 so as to achieve the greatest possible savings and in such a way that a new peak is avoided. 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 maximum number of interruptions and maximum hours 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 types of systems such as a Genco and Disco 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 market value in addition to 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 with up to seven 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 as either a deration of the unit's capacity, or as an adjustment to 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 impact 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 (Loss of Load Hours, or LOLH)
- Expected emergency energy
- Reserve Margin

Alternatively, reliability measures, such as LOLH and expected emergency energy, may be fixed so that equivalent capacity benefits for 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 each unit are input. The individual unit results are then aggregated into company and system emissions totals and rates. The cost of emissions, whether such cost is in the form of allowance purchase price, emissions tax, or emissions externalities result from the thermal dispatch. Separate inputs allow these emissions costs to be included in a unit's dispatch price if desired.

D.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 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 availability of hourly load shapes. Customer groups for which shapes are not available are processed differently than those with 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.

D.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-poor 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 transmissions 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 Network Economy Interchange reflects the market clearing price of the system. Therefore, if there are no losses, no connection charges, and no tie 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.

D.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 demand-side management (DSM) or marketing programs.

The module allows modeling of emissions-related constraints, emissions allowance trading, and emissions reduction alternatives (e.g. scrubbers, 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 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). 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 you to specify demand-side or marketing programs on an hourly chronological 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 with a separate GAF production cost 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 CER 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 is structured in a similar manner to Strategist GAF data.
- PROVIEW provides quick turn-around time by eliminating options that are not feasible and by eliminating unnecessary detail.
- PROVIEW 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 are 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.
- PROVIEW 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.
- PROVIEW 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.
- PROVIEW provides for one of five objective functions to be used in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost (total resource cost), minimization of total resource costs, or maximization of total unit profitability.
- PROVIEW will also evaluate any expansion plan optimized by one of the five objective functions mentioned above with regard to financial performance. 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.

- PROVIEW 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 (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 levels can also be specified to reduce the alternatives considered.
- A PROVIEW optimization may 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.
- When using Multi-Company, PROVIEW allows the addition of alternatives which are owned by a company other than the company (or pool) which is being optimized.
- PROVIEW 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.
- Numerous diagnostics which explain in detail how PROVIEW reaches its optimal plan decision are available.

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 section 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 Module online help and LFA Module 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 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 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 of 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 the optimal plan and the components of each sub-optimal plan.
6. The optimal plan is set up in the LFA and GAF for subsequent analysis and reporting. All plans are saved in the database.

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