Appendix E

Central Station Work Group Report

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Michigan Capacity Need Forum:
Central Station 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) established by the Michigan Public Service Commission (MPSC) in Case No. U-14231 has been charged with the task of developing forecasts of Michigan electric power supply and demand and analyzing different scenarios for resource options that best meet future demands. As a subset of the CNF a Central Station Working Group has been established and charged with three key tasks. These tasks include: (1) compiling an inventory of current generation assets within the State (2) forecasting costs associated with construction and operation of most likely new large central generation station technologies and (3) evaluating sitting issues for large central generation stations related to transmission and environmental impacts.

2 Generation Inventory

The Work Group conformed to the modeling format of evaluating generating units and issues within the State in three geographical areas. These areas are the southeastern Lower-Peninsula (ITC's service territory), "out-state" Lower Peninsula (METC's service territory), and the Upper Peninsula (ATC's zone 2). Southeastern Lower Peninsula and the out-state Lowe Peninsula have important differences because of the relatively greater concentration of demand in the southeastern Lower Peninsula compared to the relatively greater concentration of generation in the balance of the Lower Peninsula. This distinction is important because of the transmission constraints experienced by west-to-east energy flows in the recent past. The Upper Peninsula has chronic constraints caused by the lack of robust transmission interconnections with the Lower Peninsula and Wisconsin, its low concentration of load, and its reliance on one large indigenous power plant, Presque isle.

One of the tasks assigned to this Work Group was to provide an inventory of existing generation within Michigan. The purpose was to provide a descriptive summary of the generation and to provide likely service lives, capacities, and fuel requirements for modeling purposes. The MPSC Staff obtained details on Michigan generating units used by the Midwest Independent System Operator (MISO) and originally provided by generation owners to support the startup of MISO operations. The data was subsequently reviewed by the generation owners through the CNF working group and corrected where appropriate. This generation data is summarized in Figure 1.

Figure 1: Michigan Electrical Generating Unit Inventory

Eastern Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units
IOU						
Nuclear	1,110	1,125	1,110	1,110	1,110	1
Steam Generator	8,248	8,275	775	83	317	26
Combine Cycle/GT	969	1,188	82	11	31	31
Internal Comb	152	152	3	0.8	2.5	61
Muni/Coop/Public Auth						
Steam Generator	470	472	118	20	59	8
Combine Cycle/GT	25	30	25	25	25	1
Internal Comb	39	40	3	0.4	1.1	36
Non-Utility						
Steam Generator	326	338	199	1	47	7
Combine Cycle/GT	1,502	1,515	570	2	65	23
Hydro	5	6	2	0.5	1.0	5
Internal Comb	76	77	5	0.1	1.0	76
TOTAL	12,922	13,218				275

Western Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units
IOU						
Nuclear	2,820	2,898	1,060	760	940	3
Steam Generator	3,932	3,937	737	52	281	14
Combine Cycle/GT	358	438	30	2	17	21
Hydro	95	113	10	0.2	1.4	69
Pump Storage	1,872	1,872	159	153	156	12
Muni/Coop/Public Auth						
Steam Generator	840	860	158	8	40	21
Combine Cycle/GT	428	459	73	11	29	15
Hydro	8	9	1	0.1	0.4	23
Internal Comb	171	171	8	0.1	2.2	77
Wind	1	1	0.6	0.6	0.6	1
Non-Utility						
Steam Generator	355	374	30	2	14	26
Combine Cycle/GT	4,896	4,909	671	0.8	119	41
Hydro	22	22	3	0.1	0.6	38
Internal Comb	241	241	59	0.5	5	49
Wind	2	2	0.9	0.9	0.9	2
TOTAL	16,039	16,306				412

UP Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units
IOU						
Steam Generator	613	613	90	25	68	9
Combine Cycle/GT	24	28	24	24	24	1
Hydro	139	142	8	0.1	1.1	121
Internal Comb	5	5	3	2	2	2
Muni/Coop/Public Auth						
Steam Generator	82	82	44	13	21	4
Combine Cycle/GT	23	24	23	23	23	1
Hydro	10	10	1.6	0.3	1.0	10
Internal Comb	17	17	2.5	0.5	1.7	10
Non-Utility						
Steam Generator	146	155	50	2.4	21	7
Hydro	22	22	5	0.4	2.4	9
TOTAL	1,081	1,097				174
Michigan Total	30,042	30,621				861

3 Central Station Cost Analysis

The Work Group first selected the base technologies for which detailed construction and operating cost data would be developed. The options selected were: (1) Pulverized coal (super-critical or sub-critical) (2) Circulating Fluidized Bed Boilers (CFB) (3) Nuclear (4) Integrated Gasification Combined Cycle (IGCC) (5) Traditional combined cycle combustion turbines and (6) 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.

3.1 Pulverized Coal

Pulverized coal generating units rely on the conversion of coal to a fine dust, which is injected into a boiler and burned as a fuel to produce steam. The steam is used to rotate a turbine, which turns a generator and produces electricity. This process, known as the Rankine cycle, is the basis for steam-based generation throughout the world. A majority of U.S. coal plants operate at sub-critical pressures, 2,400 pounds per square inch (psi) or less, with superheat and reheat steam temperatures normally limited to 1050^0 degrees Fahrenheit. New sub-critical plants can operate at design net plant efficiencies of approximately 9,500 Btu/kWh. Design efficiencies are the heat rates expected at full load and do not include losses to efficiency due to bringing the unit online, ramping up, ramping down, or operating at partial loads. In the late 1960s super-critical pressure steam plants were introduced which operate at main steam pressures of approximately of 3,600 psi and provide net plant design efficiencies of about 8,900 Btu/kWh.

In order to operate at the higher pressure, super-critical plants require greater capital costs when compared to sub-critical plants. With comparatively low and stable coal prices, this capital cost vs. fuel cost tradeoff resulted in no clear advantage of one technology over the other in the U.S. As a result, a mix of both types of plants was built and, although both continue to be planned for the future, there appears to be a preference to build large super-critical units. Both technologies have performed well throughout the world.

One advantage of super-critical plants is their efficiencies. Since super-critical plants operate more efficiently than sub-critical plants, they require less fuel input for each megawatt hour of electrical production. This means that there are fewer emissions associated with each megawatt hour produced with a super-critical plant. Nevertheless, either plant built today would require a scrubber for sulfur dioxide (SO_2) control, a SCR system for NOx removal, and a fabric filter or electrostatic precipitator for particulate control. The implications of new mercury rules have not yet been determined and therefore the cost to install this control technology has not been included in the cost analysis summary table. A further discussion of the new mercury rule issues can be found later in this report.

3.2 Nuclear

Nuclear units also operate on the Rankine cycle, similar to coal fired electric steam generation. The source of fuel, however, is uranium and the heat is produced by fission in a controlled environment. Nuclear power plants in the U.S. have operated with high reliability and excellent safety records. The last generation of nuclear plants built around the time of the Three-Mile Island incident (1979), generally saw significant costs increases as plants were delayed and new regulations forced significant safety design changes. Spent nuclear fuel disposal remains an issue with nuclear generation. The U.S. government has constructed a waste fuel repository site at Yucca Mountain, Nevada. However, this site has yet to accept material due to unresolved environmental and political issues.

Over the last decade, a number of factors have contributed to a renewed interest in nuclear production technology in the U.S., including significantly improved safety and operational performance. For example, by 2002, average net capacity factor was over 90 percent with all safety indicators exceeding targets. Another important factor is that fuel needs for nuclear plants can be satisfied from domestic sources. Thus, unlike natural gas, nuclear power development does not result a growing reliance on foreign sources of fuel. Also, nuclear units do not emit SO_2, NOx, Hg, particulate or carbon dioxide, and, therefore, do not contribute significantly to acid rain, ground level ozone, or global warming. From an air emissions viewpoint, nuclear plants offer both low emissions and virtually no risk to new air emission regulations. Therefore, they are not likely to be subject to air quality technology retrofit costs.

Reactor designs have evolved considerably over the past thirty years, with the latest advanced reactor models designed to achieve a number of goals, namely: standardized and simpler designs; improved performance and reliability; higher fuel utilization rates; and superior safety features. Achieving these goals is expected to result in reduced construction time and costs, reduced likelihood of reactor accidents and core melt, more efficient use of fuel, and easier plant operation. Several of the designs incorporate passive safety features that rely on physics to assure major accidents do not occur.

Because no new nuclear plants have been started in the U.S. in a quarter of a century, significant uncertainties exist with respect to new plant development costs. Changes to the U.S. Nuclear Regulatory Commission's plant certification and licensing policies, intended to clarify and streamline the process, are one major source of uncertainty. While cost estimates for constructing new, advanced reactors are available from engineering studies and from construction costs incurred in Japan and plants under construction in Korea, these do not address uncertainties surrounding new U.S. licensing rules. The estimates used in this study are based on DOE's cost estimates for an advance light water reactor. However, until one is actually constructed, this cost estimate should be considered tentative. Finally, the decommissioning cost of a nuclear plant is significant and must be considered in any evaluation of new nuclear plant costs.

3.3 Circulating Fluidized Bed

Circulating Fluidized Bed Boilers (CFB) have been built throughout the world with hundreds of units currently operating. The size of CFBs continues to evolve with single boilers in the 300MW size now being offered and with dual unit 600MW systems being planned. These systems are now available with operating conditions equivalent to sub-critical and super-critical PC boilers. The advantages of CFBs are that they offer extreme flexibility in fuel type and coal quality, operate at low combustion temperatures that reduce NOx formation, and "fire" a limestone / coal mixture that reduces SO_2 without the need for a wet scrubber system.

The CFB design feeds crushed coal and limestone into a burning bed of solids. This solids mixture utilizes air introduced into the bottom of the bed to constantly re-circulate the coal and limestone mixture while introducing combustion air. Cyclones are utilized to separate entrained particles from the flue gas leaving the combustor and return the hot solids to the combustor. Modern CFB's incorporate superheater, reheater and economizer tube surfaces much like those utilized in PC boilers. A CFB operates at lower fuel combustion temperatures than PC boilers which improves its ability to reduce air emissions and to utilize lower cost steel alloys for the high temperature – high pressure components. SCR's can be added for additional NOx removal and flash dryers can be added for enhanced SO_2 removal.

3.4 Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) is an emerging technology with four coal-fired IGCC facilities in operation today. IGCC technology makes use of two power cycles; these facilities use the Brayton cycle in the combustion turbine and the Rankine cycle in the heat recovery steam generator cycle (HRSG). Two of these were built as demonstration facilities located in the U.S. and now operate commercially. Two additional units were built in Europe. All are approximately 275 MW single train plants. The two U.S. plants include one in Florida, a Tampa Electric IGCC plant employing the GE/ChevronTexaco gasification method, and the other in Indiana, the Wabash River Coal Gasification Repowering Project utilizing the E-Gas/ConocoPhillips gasification method. Two different gasification technologies are in use in Europe, the Shell technology is being used at one plant in the Netherlands, and the Prenflo technology is being used at a plant in Spain.

IGCC plants gasify coal by reacting coal with steam and controlled amounts of oxygen under high pressures and temperatures. The heat and pressure result in a synthesis gas (syngas) being formed that is made up primarily of carbon monoxide and hydrogen. The syngas is cleaned and then combusted in a gas turbine. From this point in the electrical generation cycle, the IGCC plant operates like conventional natural gas fired combined cycle units. The IGCC plant includes an air separation unit to produce the oxygen required in the gasification process. Air separation units add significant capital cost to the overall process and require large amounts of station power.

Although gasifying coal is a commercially proven process and is used throughout the world in the chemical industry, its integration with a combined cycle combustion turbine cycle results in operational complexity beyond that of a PC plant.

The U.S. demonstration IGCC plants were designed to operate with a bituminous coal source. The use of low cost, low quality high ash content coals will result in a reduction in plant performance results. Thus current gasifier technology has not been proven to be cost effective with non bituminous coals. Although IGCC costs utilizing PRB coals are shown in the summary cost table, this data is based on pilot plant comparative data since no commercial size gasifiers are operating on PRB coals.

To date IGCC technology has not been commercially deployed because of its higher capital cost and its technology risk. American Electric Power (AEP) is in the process of performing an engineering study in concert with GE and Bechtel on the design of a 600 MW IGCC plant for 2010 operation in Ohio, West Virginia, or Kentucky with potential plans for a second 600 MW unit for operation at a later date. This would represent the first commercial U.S. application of this technology beyond the demonstration plants currently operating.   To support the construction of this new technology AEP is requesting that ratepayers contribute to its development costs and to be provided with the certainty of recovery of its costs. At this time it is uncertain if AEP will receive this regulatory treatment for implementation of IGCC technology.

Engineering studies with GE and Bechtel show that the 600 MW IGCC plant being developed for AEP will have air emissions that are inherently, depending on the individual pollutant, either equivalent to or substantially lower than those from a fully controlled (i.e. with SCR and scrubber) pulverized coal plant. Sulfur dioxide (SO2) and carbon monoxide (CO) emissions from an IGCC plant are expected to be substantially lower than those from a fully controlled pulverized coal plant, while NOx, particulate matter (PM) and Volatile Organic Carbon (VOCs) emissions from the IGCC plant are expected to be similar to those of a fully controlled pulverized coal plant. The IGCC plant will also have a mercury removal component that is expected to result in a removal of at least 95 percent of the mercury in the gas stream prior to combustion.

Another major advantage of IGCC technology that has drawn adherents is the potential of IGCC plants to allow more economic capture of carbon dioxide than might be achievable with PC boilers. This would be important should carbon dioxide become a future controlled emission in the U.S., and if sequestration becomes a proven technology. Again, capital or operating costs to achieve carbon sequestration are not known at this time and, therefore, are not included in the technology cost table.

3.5 Combined Cycle Combustion Turbines

Combined cycle combustion turbines rely on a two-stage process of electricity production. Although these plants can also utilize #2 fuel oil, the vast majority of CCCT's operate with natural gas as their only fuel option. Natural gas is first combusted and used to turn a gas turbine. The hot exhaust air from the gas turbine is routed though a heat recovery steam generator, which produces steam. The steam is then used to turn a conventional steam turbine, which turns an electric generator for additional electrical energy. By capturing the exhaust gas from the gas turbine in order to produce a steam cycle, the combined cycle plants can reach design net plant efficiencies of 7,200 Btu/kWh. A number of combined cycle plants have been built in Michigan since 2000. These include the CMS DIG (760 MW), Kinder Morgan (Jackson, 550 MW), Renaissance (Carson City, 546 MW), Mirant Zeeland (830 MW), and Covert Township (1170 MW).

Combined cycle units are relatively efficient, with comparatively favorable emissions characteristics and have been reasonably easy to site and build. The schedule to build a gas plant is estimated to be from one to three years depending on whether the plant built is a simple or combined cycle unit. A coal unit on the other hand is estimated to take at lease six years from the start until the plant becomes operational. Natural gas plants have one big drawback, however, they are dependent on natural gas prices, which recently have been very volatile. At current natural gas prices combined cycle plants cannot economically serve the role of baseload plant. Instead, these operate only during peak demand or near peak demand conditions. The high current natural gas prices, compared to the electricity market prices and the high reserve margins in the region have resulted in many combined cycles plant projects being delayed or abandoned in the State of Michigan and in neighboring states.

3.6 Combustion Turbines

Combustion turbines (CT) are simple cycle plants that are used strictly for peaking or emergency purposes. Many of these plants are dual fuel, capable of operating with both natural gas and fuel oil. The plants use fuel to create a hot gas that spins a turbine, which turns a generator to produce electricity. There is no heat recovery system associated with these plants, and new unit designs can be expected to have heat rates of approximately 10,450 Btu/kWh. These plants can move quickly from investment decision to operation, have low capital costs and low fixed operating but very high variable operating costs due to their low cycle efficiencies and the high cost of fuel.

4 Technology Cost Estimates

Table 1, Technology Price Estimates summarizes the Central Station Working Group's estimates of the costs and typical emissions profiles associated with construction and operation for each type of plant described above. Plant construction costs include land, boiler, turbine and electrical switchyard components. Plant cooling water, coal transportation and transmission connection costs are unknown until specific plant locations are selected, but have been included as generic costs. Transmission system upgrades necessary to move the power from a new plant to electrical load centers is not included in any estimates provided and could vary widely dependent on plant location and current transmission design and loadings.

Construction costs are provided as "overnight costs" meaning that any interest costs to finance the plant during its construction period are not included, nor is the effect of inflation included in overnight costs. Plant costs are assumed for a "green field site" meaning that these units are not being constructed at an existing power plant site and, therefore, are unable to take advantage of existing infrastructure. There will be limited opportunities in Michigan to add units at existing plant sites, the exact number of and cost advantage of these are unknown at this time. The fact that many counties in southeastern Michigan have been designated as non-attainment for various environmental pollutants, as reflected in the pictorials below, means that extra measures or costs could be incurred to construct coal-fired power plants near the southeastern Lower Michigan load centers. Depending on siting, it is likely that any new coal plant, regardless of the level of environmental control technology employed, would face resistance. The following maps show the current ozone non-attainment counties in Michigan, and the southeastern counties that are also currently designated as non-attainment for PM 2.5 (particulate matter less than 2.5 micron in size).

Figure 2: Current Ozone Non- Attainment Counties in Michigan

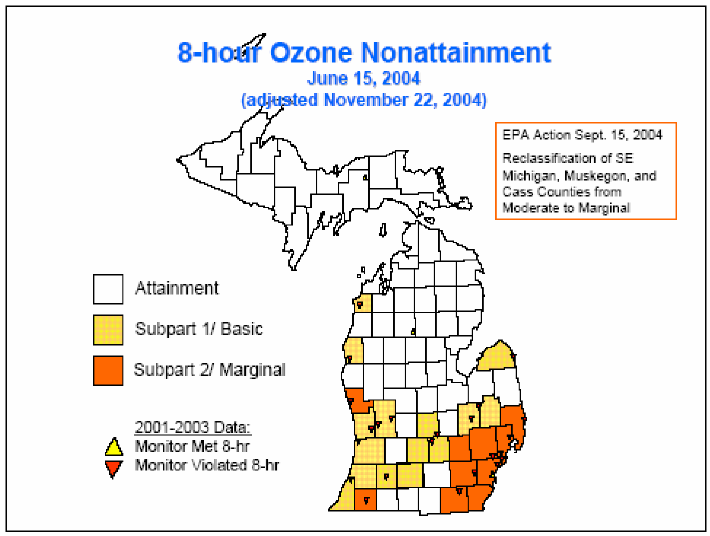

Figure 3: Southeastern Michigan Counties Currently Designated as Non-Attainment for PM 2.5

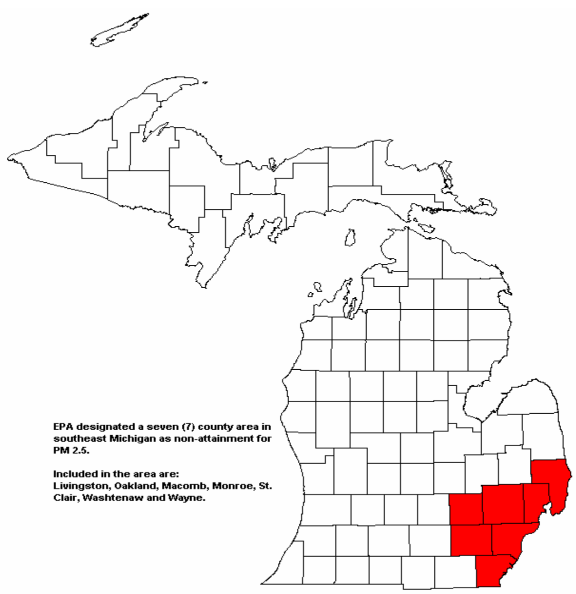

Table 1: Technology Cost Estimates (2005 Dollars)

Technology	Size	Construction ($/kW)	Fixed O&M ($/kW)	Var. O&M ($/MWh)	Design Net Plant Heat Rate (BTU/kWh)
Pulverized Coal					
Sub-critical	500	1,370	42.97	1.80	9,496
Super-critical	500	1,437	43.60	1.70	8,864
Fluidized Bed	300	1,505	44.77	4.24	9,996
IGCC	550	1,647	59.52	0.95	9,000
IGCC – PRB Fuel	550	1,845	59.52	0.95	10,080
Nuclear	1000	2,180	67.90	0.53	10,400
Combined Cycle	500	467	5.41	2.12	7,200
Combustion Turbine	160	375	2.12	3.71	10,450
	Fuel Cost $/MMBTU	**Capacity Factor**	**Dispatch Cost ($/MWh)**	**Fixed Costs (Capital +O&M $/kW)**	**Bus Bar Costs ($/MWh)**
Pulverized Coal					
Sub-critical	1.25	85%	13.67	27.85	41.53
Super-critical	1.25	85%	12.78	29.01	41.79
Fluidized Bed	1.25	85%	16.74	30.27	47.01
IGCC	2.75	80%	25.70	36.70	62.40
IGCC – PRB Fuel	1.25	80%	13.55	40.08	53.63
Nuclear	0.50	90%	6.23	41.79	48.02
Combined Cycle	6.00	45%	45.32	15.58	60.90
Combustion Turbine	6.00	5%	66.41	107.58	174.00

The construction cost estimates shown in Table 2 were completed in 2004 and are based on the EIA/DOE Annual Energy Outlook 2005, a DOE and National Coal Council report entitled "Opportunities to Expedite the Construction of New Coal-Based Power Plants"[1] and CNF Work Group participant inputs. It should be noted that the construction forecasts do not reflect the current major cost run ups in steel and concrete commodity price that have been the result of China's major building program. Mercury control equipment construction costs and operating costs are similarly not included in the above estimates. Both of these could impact price forecasts by 15 percent or more. As previously stated the above costs do also not include any transmission system upgrade costs that would be required to move the generation to the load demand center.

[1] Opportunities to expedite the construction of new coal-based power plants / Michael J. Mudd, American Electric Power Company, Thomas G. Kraemer, Burlington Northern Santa Fe Railway, Georgia Nelson, Midwest Generation, EMC, LLC. Washington, DE : National Coal Council, 2005

Figure 4: Relative Construction Costs for Various Technologies

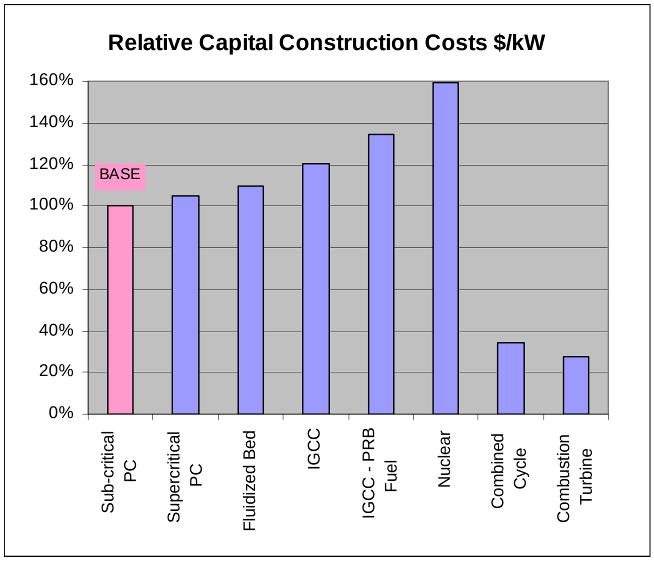

Figure 4 shows the relative construction costs of the various technologies analyzed. This data is consistent with multiple forecasts reviewed by the working group. For modeling purposes it was deemed more important for cost information on competing technologies to have the correct relative position and magnitude than it was to improve accuracy by obtaining precise construction cost estimates developed through more complete engineering analyses. In part, this was a necessity; since more accurate cost estimates are dependent on unit size, permit standards, the specific site location, etc. There are no proposed units for construction in Michigan currently at a stage that would allow this more specific information to be compiled. As the planning process moves forward and more detailed information becomes available, more specific cost estimates may be possible.

5 Technology Emission Characteristics

Emission rates are shown for a typical plant assuming PRB coal for the PC, CFB and IGCC units. Data sources are the National Coal Council Report[2] and "Financial Incentives for Deployment of IGCC: A Coal Fleet Working Paper", Senate Committee on Energy & Natural Resources Bipartisan Coal Conference March 20, 2005, Washington, DC.

[2] See Footnote 1.

Table 2: Plant Typical Emission (pounds per million Btu)

	SO_2	NO_x	Particulate	Hg	CO_2
Pulverized Coal					
Sub-critical	.05	.08	.015	1.22E-06	201
Super-critical	.05	.08	.015	1.22E-06	201
Fluidized Bed	.02	.10	.015	1.22E-06	200
IGCC	.03	.06	.006	8.05E-07	195
Nuclear	.00	.00	.00	.00	.00
Combined Cyde	.001	.03	.00	.00	120
Combustion Turbines	.001	.03	.00	.00	120

6 Major Assumptions and Issues

6.1 Plant Retirements

To perform a long-term analysis integrating generation, transmission and demand, the retirement of existing generation assets must be addressed. Without considering prospective retirements, the future need for new generation resources will likely be understated. This is particularly true for Michigan, due to the age distribution of existing generation assets.

A general review of service lives of Michigan baseload generating units showed that 50-55 years was typical for coal based generation constructed before 1950. These retired units can generally be described as small in size, (less than 75 MW per boiler), and lower efficiency (with heat rates greater than 11,000 Btu/kWh). The low efficiency was the result of the technology of the time for which boiler operating pressures were 1,500 psi or less, superheater steam temperature limits were 950^{o} F and systems did not include reheaters or intermediate pressure (IP) turbines.

Since the late-1950s, the basic thermodynamic design of steam electric generating units has changed little due to metallurgical limits of high temperature steel alloys. In the late 1950s main steam pressures of 2400 psi with $1000/1000^{o}$F main steam/reheat temperatures became typical. Modern sub-critical electric central generating units are being built today to these same basic parameters. The most notable change of the last 50 years in sub-critical boiler design has been increased unit output capacity (unit size). A typical late 1950s unit would have been capable of producing 250-300MW, new units are now built in the 600-700MW size. The advantage of the increased size is less operating and maintenance costs per megawatt hour of electricity produced.

This Work Group discussed these issues and agreed that units built since 1950 should expect to realize longer economic life than older units. The group recommends a 65 year retirement age be used for modeling of coal fired generating units. While it is likely that some will retire sooner than 65 years old and some will retire later, 65 years is a reasonable modeling assumption.

Although boiler and turbine components can be economically replaced almost indefinitely there are other issues that will move existing coal fired units towards retirement. The issues of size, age, component replacements and environmental investment will all work against maintaining these units in service. The major investments required to meet evolving, ever-tightening air emissions limits on coal-fired electric generating units will create additional economic pressure on smaller and older units. Support for continued operation of these units comes from high natural gas prices, demand growth and the long lead-time required to permit, design and construct large new central generating units.

Nuclear unit retirement dates were also reviewed by the group. Original plant licenses were granted for 40 years, but it now seems likely that extensions of another 20 years will be granted. This 60-year life is in concert with that of coal plants discussed above.

Combined and simple cycle peaking units have both a low capital cost structure and a short construction lead-time requirement. These factors combine to preclude the need to consider retirement dates for these types of units.

6.2 Environmental Issues

The Work Group identified two major issues related to air quality standards. First, seeking an air permit for a new coal fired central generating unit will require addressing a number of critical issues, many of which are currently uncertain or speculative. The uncertainty arises because no new coal units have been placed in service in Michigan since 1985. Therefore, air quality permitting remains potentially uncertain, lengthy and difficult. The second major issue is the uncertainty of future air emission regulations both with regard to tightening of existing limits and the potential regulation of additional combustion byproducts such as carbon dioxide.

To obtain the necessary environmental permits to install a new electric utility generating unit today, the air emission control equipment must meet; 1) the Federal Standards of Performance for New Stationary Sources, commonly referred to as New Source Performance Standards or NSPS, 2) requirements of the New Source Review (either Prevention of Significant Deterioration or Non-attainment Area permitting regulations) program and 3) any applicable Maximum Achievable Control Technology (MACT) requirements for hazardous air pollutants. In addition, any new generating unit must meet all other federal and state emission limitations (i.e., new federal mercury and clean air interstate rules). The most stringent requirement will ultimately drive the emission control equipment specification for each regulated pollutant. NSPS requirements are found in 40 CFR Part 60. The Environmental Protection Agency (EPA) updates these requirements periodically.

The New Source Review (NSR) process requires adoption of either Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) regulations for major emission sources depending on whether or not the new generation will be located in an attainment area for National Ambient Air Quality Standards (NAAQS). For non-attainment areas, in addition to LAER emission controls, the new source owner must also provide (obtain or purchase) a greater than 1 for 1 offset of any significant increase in emissions of a nonattainment pollutant. Generally LAER requirements are more stringent than BACT; however, that is not always the case. LAER, once specified, can become a default BACT. The major difference in the BACT/LAER determination is that cost is a factor in establishing BACT that is not present with LAER. The EPA maintains a database, in their BACT/LAER Clearinghouse, on BACT and LAER determinations (emission limitations) that have been made across the country. Generally, BACT and LAER are more restrictive than NSPS requirements but it has not been recently updated.

EPA revised its December 2000 regulatory finding issued pursuant to Section 112, removing coal and oil-fired electric steam generating units from the CAA Section 112c source category list. Section 112 addresses hazardous air pollutants (HAPs) like mercury, arsenic, etc., and major sources of HAPs are subject to MACT standards. This means coal-fired electric utility steam generating units are a "delisted source category" from Section 112c and are no longer subject to a MACT regulation. However, in March 2005, the EPA signed two new rules that materially alter future air emissions from power plants. On March 10, 2005 the final Clean Air Interstate Rule (CAIR) was published that will permanently decrease emission caps for sulfur dioxide (SO_2) and nitrogen oxides (NOx) in 28 eastern states. On March 15, 2005 EPA signed the Clean Air Mercury Rule (CAMR). Both new and existing coal fired power plants are affected by CAMR, which proposes a cap-and-trade program in two distinct phases. The first phase creates a nation wide cap of 38 tons beginning in 2010, with a final cap of 15 tons implemented in 2018. Individual states have the opportunity to participate in the nation wide cap-and-trade program or to require their power plants to comply on a more regional or even an individual statewide basis. CAMR also provides mercury NSPS for new electric utility generating units.

Finally, all State air permitting regulations must also be satisfied (i.e, air quality impact analysis, alternate site review, etc.). In Michigan, the federal NSPS, BACT and LAER requirements will be the most stringent emission control requirements for new power plant installations. It should be pointed out that the Michigan Department of Environmental Quality (MDEQ) Air Quality Division is in the process of preparing a revision of the Michigan SIP (State Implementation Plan), for EPA approval. This is intended to establish a Michigan-specific NSR program. The State of Michigan must also prepare a SIP-like plan (rules) for CAMR. If the State implements requirements in excess of those required under CAMR the costs to construct and operate new coal fired electric generation could materially increase and shift the economics of new central generation station towards nuclear or gas combustion turbines. To understand the impact of differing mercury regulations on electrical generation station needs in Michigan the work group has recommended modeling both a Federal and a State only mercury cap-and-trade program.

Michigan has not permitted a new coal-fired power plant since the 1980s. Historically, permitting agencies have evaluated permit applications based upon the level of control placed on the process, and have not mandated that applicants evaluate other alternate processes which may allow the unit to be able to achieve better levels of environmental performance. Recent appeal actions have challenged this review process and are asking that permit reviewing authorities consider alternate processes in the permit review process.

In recent months there have been appeal actions that have challenged the type of coal burning technology chosen by a permit applicant. IGCC has been receiving support and from some groups because of the purported favorable environmental performance, as compared to conventional pulverized coal furnaces of the same generating capacity. An unresolved issue is whether or not IGCC needs to be considered as an alternate technology to conventional coal-fired power plants. Recent permitting activities in EPA's Region V have asked applicants to consider IGCC, but have not forced an applicant to use the technology since some would consider IGCC not to be "commercially available" technology. There has been much debate over the reliability and cost of IGCC technology. If a permitting agency advances an air use permit without a comprehensive and convincing review of IGCC technology, there is a very high likelihood that the permitted use of the conventional pulverized coal-burning technology (Pulverized Coal-Fired Combustion, Circulating Fluidized Bed Combustion, Critical and Super-critical coal-fired boilers) could be contested or appealed. While there appears to be a move towards IGCC technology with several utilities announcing plans to build new generating capacity based upon this new technology in other states, we believe that this technology must be assessed like all other resources by considering its costs, emissions profiles, and operating availability along with those of other generating technologies.

Natural gas and oil-fired boilers would likely be less challenging to permit than coal-fired boilers. All boilers, if of sufficient size, could face additional challenges depending on where they choose to locate. Generally, in "non-attainment" areas (those areas of the state not meeting National Ambient Air Quality Standards for one or more criteria pollutants), there are more stringent environmental standards. Of particular concern to the permit applicant is the requirement to have "emission offsets" previous to constructing the boiler. In effect, the emission-offset requirement obligates the permit applicant to offset the "new" emissions from the boiler by reductions of that pollutant from other sources in the area. Emission offsets could be generated from equipment, which is shut down, or by additional levels of control placed on existing emissions sources. A permit applicant must acquire a greater reduction in the pollutant than they are estimated to emit from the proposed installation. Typically, this requirement is problematic for a permit applicant.

Finally, our review of central station generating options does not include explicit consideration of any future controls related to carbon dioxide. It should be noted that the EPA is not now authorized to develop or promulgated, any rules relating to carbon dioxide abatement. However emissions that may contribute to global warming represent a continuing issue for energy planners. In order to assess the impact that a carbon abatement policy may have on generation options in Michigan, the modeling group will perform one or more environmental scenarios, including carbon mitigation.

For a more detailed discussion of the Clean Air Act history and emission standards, please see Appendix I to this report.

7 Summary

The CNF has identified base load generating unit technologies, cost structures and environmental issues that will form the basis for a statewide comprehensive electric energy resource plan. While electric energy modeling will provide a view of the best economic alternative and mix of generation equipment to meet the future needs of the State, historical lessons indicate that fuel diversity is critical to any future planning effort. The oil embargo of the 1970s, the Three Mile Island incident of 1979 and the current natural gas price spike all show that over reliance on one fuel source can create significant future risk. The Work Group also notes that a number of technological and policy developments are unfolding that could have an impact on the generating technology selected for Michigan. The Work Group will continue to stay abreast of these developments and provide updates to this report if needed.

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Appendix I

Electric generating plants, including coal-fired plants, are major sources of air contaminants. Approximately 40 percent of Michigan's electric generating capacity and 60 percent of the energy produced in Michigan come from coal-fired power plants. For example, Michigan's electric generating plants burned 34 million tons of coal and emitted 317,611 tons of SO_2 and 105,825 tons of nitrogen oxides into the atmosphere in 2003. This represented 88 percent of Michigan's total emissions of SO_2 and 84 percent of the State's total NOx emissions. Emissions from these generating plants are subject to requirements of the Clean Air Act (CAA).

The original CAA was signed into law in 1963 and was considered the first modern environmental law enacted by the US Congress. The CAA of 1970, reviewed and amended in 1975 and 1977, forms the basis of the Federal air pollution control program currently in place. The CAA of 1970 represented a major public policy initiative to assure maximum acceptable levels of pollutants for outdoor air by setting National Ambient Air Quality Standards (NAAQS). The NAAQS established maximum limits for six criteria pollutants. The criteria pollutants are sulfur dioxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), ozone, lead, and particulate matter (PM).

A preconstruction permitting process for new major sources of criteria pollutants and modified major sources of criteria pollutants called New Source Review (NSR) was required. In areas of the country in attainment for NAAQS, the NSR process imposed emission limits to prevent deterioration of air quality and sources were required to meet Prevention of Significant Deterioration (PSD) standards. In areas of the country not meeting NAAQS (in nonattainment), a different NSR process requires emission limits that are more restrictive than PSD limits. Under nonattainment NSR, the source must obtain emission reductions at other sources so that no net increase in overall area emissions occurs in order to achieve attainment of the NAAQS in the applicable areas.

As part of the CAA of 1970, eight substances were listed as hazardous air pollutants (HAPs) and National Emissions Standards for Hazardous Pollutants (NESHAPS) were promulgated for sources of seven of these pollutants. EPA promulgated New Source Performance Standards (NSPS) that set emission limits on specific new sources and modifications of existing sources. Additionally, states were required to develop State Implementation Plans (SIPs) to achieve acceptable air quality within the state.

The Clean Air Act Amendments (CAAA) of 1990 further addressed the attainment of health-based air quality standards along with continuing concerns about the CAA itself. Nonattainment for one or more of the NAAQS was separated into categories (marginal, moderate, serious, severe and extreme) with differing deadlines to attain the NAAQS. The Air Toxics program identified 189 chemicals as HAPs and adopted new technology standards to reduce emissions of HAPs. Identified sources that emit HAPs will need to comply with the new technology standards and achieve Maximum Available Control Technology (MACT) limits. If necessary, further reduction in HAP emissions may be required if there remains a significant residual health risk after implementation of MACT.

The Acid Rain program was part of the CAAA of 1990 and is a two-phase utility power plant program for reducing sulfur dioxide emissions by 10 million tons from 1980 levels. It was the nation's first emissions cap and trade program. The cap and trade program offered emission sources the choice of capital investments to comply with emission caps or the possession of emission allowances that could be purchased in allowance markets. The amendment required that major sources have operating permits, and that the permits specify the sources compliance requirements. Operating permits are granted for no longer than five years.

The CAA and its amendments now consist of six titles: (I) Air Pollution Prevention and Control, (II) National Emission Standards Act, (III) General, (IV) Acid Deposition Control, (V) Permits, and (VI) Stratospheric Ozone Protection. Three of these apply directly to the electric generating industry.

Although the Federal government has relied upon states to implement the standards adopted by the CAA and its amendments, the EPA has been active in a number of important programs. Among these programs are the acid rain, air toxics, and interstate transport programs. Titles I and IV of the CAA are particularly relevant to the electric generating industry. These titles, together with the permitting process imposed by Title V, have a direct affect on electric generation planning and plant siting.

I.1 New Generating Plant Construction and Major Modifications to Existing Plants

New electric generating plants and modifications of existing plants require preconstruction permits to install and operate. Generally, permits require that the new plants or modifications meet certain standards for air emissions. These sources must go through an NSR process and at a minimum must meet NSPS. These requirements are part of Title I of the CAAA.

If construction occurs in an attainment area, NSR requires use of the Best Available Control Technology (BACT). The BACT technology is used to determine the allowable rate of emissions of criteria pollutants. For example, one of our modeling assumptions was that BACT required flue gas desulphurization (FGD or scrubber), selective catalytic reduction (SCR), and a fabric filter (bag house) for a new pulverized coal plant built in an attainment area. The rate of emission for a new coal plant might be expressed as a concentration standard such as pounds of emissions per million BTU of energy input. In addition to the concentration standard, NSR may require a mass emission standard to limit potential to emit, for example in pounds per hour or tons per year.

New source standards also require that a new emissions source does not cause an existing attainment area to degrade into a nonattainment area. Therefore, even if a new source meets the rate of emissions established by BACT, it must also satisfy a PSD review. A PSD review requires an ambient air analysis to assure that the proposed new source will not cause a significant deterioration in applicable ambient air concentrations. This includes the emissions from the new source along with emissions from existing sources. To protect against excessive degradation in the existing ambient air concentrations, NSR may require a concentration based emissions limit and a mass emissions limit in the permit.

Applicable BACT technology may differ from area to area and through time. BACT reflects the use of the best technology available taking into account site specific environmental, energy, and cost factors. Because of the consideration of these factors, the required emission rates may not be the lowest achievable, but are the best available.

NSR standards for nonattainment areas require use of Lowest Achievable Emission Rate (LAER). In addition to complying with LAER control technology requirements and emission rates, a new installation in a nonattainment area requires that offsets be secured for each criteria pollutant not in attainment. Offset standards require that more offsets be secured than the facility is expected to emit. For example, a permit for an electric generator expected to emit 300 tons of NOx in a nonattainment area would require that offsets totaling more than 300 tons be secured by the new source. The amount of offset depends on the classification of the nonattainment area, for example whether the area is classified as marginal or moderate.

LAER standards are not based upon the same environmental, energy, and economic considerations, like BACT. Instead, LAER standards for nonattainment areas require adoption of the lowest emissions technology for the process being permitted. However, the processes must be comparable. For example, a new coal fired source must be compared to the lowest emission rates for other coal-fired sources, not gas fired sources.

Eight counties in southeast Michigan and two counties in western Michigan are marginal nonattainment areas for ozone. Fifteen counties are basic (unclassified) nonattainment areas for ozone. Seven counties in southeast Michigan are also nonattainment areas for PM 2.5. Therefore, new construction in these areas would require LAER standards as part of the NSR process and would require offsets for the applicable criteria pollutants.

I.2 Acid Rain, CAIR, CAMR and Regional Haze

New generating units along with existing units must also meet emission limits established for the Acid Rain Program, NOx SIP Budget Program, Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Regional Haze program standards. These programs set maximum state and region-wide emission caps in tons per year for SOx and NOx, and pounds per year for mercury. These programs do not control the emission rates, but do limit the total emissions from power plants in Michigan.

The Acid Rain rules limit SO_2 using a cap and trade compliance strategy and NOx by setting an emission limit based on the type of coal-fired boiler in use. The Acid Rain program was initiated by the CAAA of 1990 and was implemented in two phases. Phase one began on January 1, 1995 and ended on December 31, 1999 and affected two units at one facility. Phase two began on January 1, 2000 and 79 units at 25 existing sources were allocated SO_2 allowances. All new affected sources were not allocated allowances and are required to purchase SO_2 allowances through the cap and trade program to cover any SO_2 emissions.

The NOx SIP Budget Program went into effect in Michigan in May of 2004. This program places state and region-wide emission caps in tons per ozone season for NOx. This program will remain in effect until the CAIR state regulations are promulgated and approved. Sources affected are located in the fine grid zone area only (roughly all counties south of a line from Pentwater to Harbor Beach). The electric generating units (EGUs) are limited to 29,038 tons for 2004 through 2006 ozone seasons. The EGUs are limited to 28,150 tons from 2007 until the CAIR requirements are in affect

CAIR rules are currently being written by the Department of Environmental Quality. These rules are aimed at controlling NOx as a precursor to ozone. The rules also aim at controlling SO_2 and NOx as precursors to PM 2.5. Phase I of the CAIR rules will limit NOx annual emissions in Michigan to 65,304 tons beginning in 2009 and limit SO_2 emissions to 178,605 tons. Beginning in 2015, Phase II will limit the NOx annual emissions to 54,420 tons and the SO_2 emissions to 125,024 tons, statewide. The annual NOx and SOx regulations will only affect EGUs larger than 25 MW, statewide.

The ozone season portion of the CAIR NOx requirements will affect EGUs larger than 25 MW statewide and other large boilers (greater than 250 MMBtu per hour heat input) in the fine grid area only. The EGUs will be limited to 28,971 tons during the ozone season for Phase I (2009 through 2014) and to 24,142 tons for Phase II (beginning in 2015).

EPA revised its December 2000 regulatory finding issued pursuant to Section 112, removing coal and oil-fired electric steam generating units from the CAA Section 112c source category list. This means coal-fired electric utility steam generating units are a "delisted source category" from Section 112c and are no longer subject to a MACT regulation. However, these plants are subject to the Clean Air Mercury Rule. State mercury rules have not been drafted as of this writing. CAMR calls for a two-phase reduction approach and implements an NSPS for mercury emissions from new EGUs. The first phase limits Michigan to 2,606 pounds per year by 2010 and the second phase limits Michigan to 1,034 pounds per year by 2018 (66 percent reduction). States, however, are permitted to adopt more stringent standards, and these are under consideration for Michigan.

The Regional Haze standards apply to those EGUs going into service between 1962 and 1978 that have the potential to emit more than 250 tons of SOx, NOx, volatile organic compounds (VOCs), or PM. EGUs and other sources also have a demonstrated significant impact on the visibility of any Class 1 area, regardless of distance.

Two Michigan plants that fall into this category are We Energies Presque Isle Plant in the Upper Peninsula and Detroit Edison Monroe Plant in the Lower Peninsula. Others EGUs and non-electricity generating sources may be impacted as well. Control standards call for adoption of the Best Available Retrofit Technology (BART). BART technology is not particularly well defined. It depends on numerous factors including plant characteristics, current control levels, control costs, technology options, and the economic impacts to the company.