DRAFT REPORT

Central Station Working Group

May 2005

DRAFT – For Review and Discussion
REV 2

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) performing 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 3) evaluating siting issues for large central generation stations related to transmission and environmental impacts.

Generation Inventory

The working group decided to evaluate issues within the State in three distinct geographical areas. These areas include the eastern Lower-Peninsula, "out-state" Lower-Peninsula and the Upper Peninsula. Eastern Lower-Peninsula and the out-state Lower-Peninsula have important differences because of the heavier concentration of demand vs. generation in the eastern Lower- Peninsula compared to heavier concentration of generation vs. demand in the remaining out-state Lower-Peninsula area. This distinction is important because of the transmission constraints related to west-to-east energy flow limitations. The Upper Peninsula is an area that has its own issues caused by the lack of transmission interconnections with the Lower Peninsula, its low concentration of load and its heavier ties to Wisconsin compared to the Michigan Lower Peninsula.

Details on generating units collected by the Midwest Independent System Operator (MISO) from generation owners in support of the startup of MISO operations were obtained by the MPSC staff and reviewed by the generation owners through the CNF working group. This data has been corrected as needed and is attached in summary form as follows.

Since all of this data is reflected in the MISO database, except for generator type, I think we should provide the summary as a table in this report. Three regions with summary by generation owner including summaries by fuel type or generator type such as base load, cycling or peakers. For retirement dates, the group decided on 60 years for coal,

nuclear would be re-licensed and CT's replaced as they are retired so no change in capabilities. If we decide to reflect this data in the table, then these assumptions should be used.

The Data below is preliminary and needs to be updated

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

Central Station Cost Analysis

The working group first dealt with the issue of selecting the base technologies for which detailed construction and operating cost data would be developed. The options selected were 1) Pulverized coal (supercritical or subcritical) 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.

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 subcritical pressures, 2,400 pounds per square inch (psi) or less, with superheat and reheat steam temperatures normally limited to 1050 degrees Fahrenheit. New sub-critical plants can operate at design net plant efficiencies of approximately 9,500 BTU/kWh. In the late 1960's supercritical 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, supercritical 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 winner between sub-critical and supercritical plants in the U.S. As a result, a mix of both types of plants were built and continue to be planned for the future. Both technologies have performed well throughout the world.

One advantage of supercritical plants is their efficiency. Since supercritical 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 less emissions associated with each megawatt hour produced with a supercritical plant. Nevertheless, either plant built new 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.

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 waste disposal is still an issue that needs resolution. The U.S. government has constructed such a site at Yucca Mountain. This site has yet to accept material due to environmental and political issues. Moreover, the decommissioning cost of a nuclear plant is significant and must be considered along with the spent nuclear fuel disposal issue in any decision to build a new nuclear plant.

These older design units would not be built as a new plant today, but there are a number of new reactor designs being proposed by the nuclear industry. If one or more of these proposals result in a standardized design(s), the cost competitive position of nuclear plants could be greatly improved. At this point in time it is not clear which design(s) and set of costs are likely to be incurred with a new generation of nuclear plants.

On the positive side, 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 environmental air emissions viewpoint, nuclear plants offer both low emissions and virtually no risk to new air emission regulations and the associated technology retrofit costs.

Circulating Fluidized Bed

Circulating Fluidized Bed Boilers (CFB) have been built throughout the world with hundreds of units currently operating. The size of CFB's continues to evolve with single boilers in the 300MW size now being offered with dual unit 600MW systems being planned. These systems are now available with operating conditions equivalent to sub-critical and supercritical PC boilers. The advantage of CFB's is 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.

Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) is an emerging technology with four coal-fired IGCC facilities in operation today. Two of these are demonstration facilities located in the U.S. and two are located in Europe. The two U.S. plants include one in Florida, 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 additional 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 require that coal be gasified 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 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 unit. The IGCC cycle includes an air separation unit to produce oxygen required in the gasification process. Air separation units add significant capital cost to the overall process, require large amounts of station power and add additional availability risk to the electrical generation process cycle.

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. Generally, the demonstration plants have encountered technical and operational difficulties that have reduced the plants' availabilities. To achieve the required cycle availability required to compete with base load coal or nuclear generation an IGCC plant will need to be built with a spare gasifier. The use of a spare gasifier increases the capital cost of the 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 compared to current gasification plants. Current gasifier technology has not been proven to be cost effective with other than 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 scoping study in concert with GE and Bechtel on the design of a 600 MW IGCC plant for 2010 operation in Ohio 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 offsets the 15-20 percent higher cost of this technology, when compared to traditional pulverized coal systems, AEP is requesting ratepayers contribute to the development costs. At this time it is uncertain if AEP will receive this regulatory subsidy for implementation of IGCC technology.

IGCC technical literature reports that this technology offers significantly lower emission levels for SO_2, NOx and Hg. Due to the high cost of IGCC technology, AEP is proposing to build its first IGCC plants without adding the additional equipment required to achieve these lower emission levels. The costs shown in the following table for IGCC technology do not include the additional capital or operating costs required to achieve emission levels lower than conventional PC plants. The major issue that has the environmental community favoring this technology is the potential of IGCC plants to allow more economic sequestration of carbon dioxide than might be achievable with PC boilers, should that be 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 and therefore are not included in the technology cost table.

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 (750 MW), Need to check the DIG number Kinder Morgan Jackson (550 MW), Renaissance (Carson city) (546 MW), Mirant Zealand (830 MW), and Covert Township (1170 MW).

Combined cycle units are relatively efficient, with comparatively favorable emissions characteristics. They are, however, 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 are run 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. .

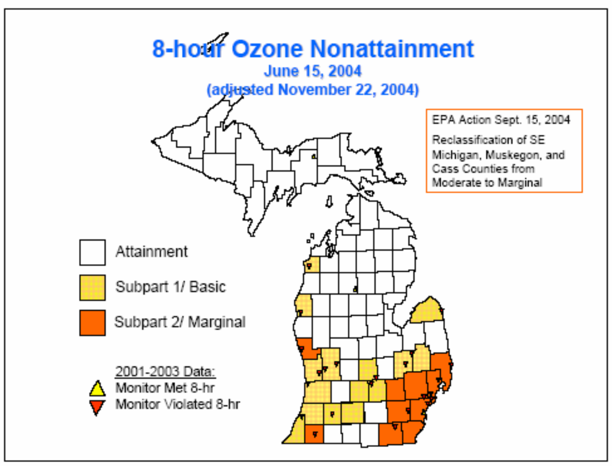
Combustion Turbines

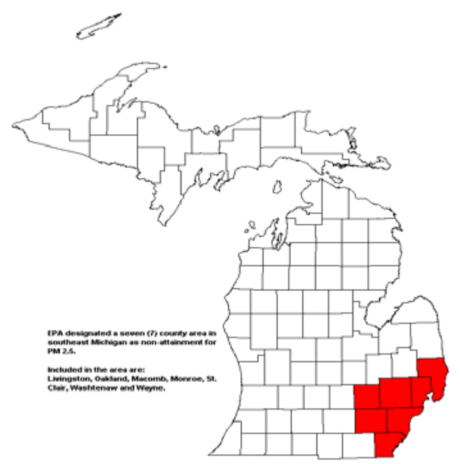
Combustion turbines (CT) are simple cycle plants that are used strictly for peaking or emergency purposes. Many of these plants are dual fuel, capable of operating with both natural gas and fuel oil. The plants use fuel to create a hot gas that spins a turbine, which turns a generator to produce electricity. 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.

General

The following table summarizes the Central Station Working Group's forecast of costs and typical emissions 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 the 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. Plant costs are assumed for a "green field site" meaning that these units are not being constructed at the site of an existing power plant and can therefore not take any 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 S.E. Michigan load centers. It is likely that any new coal plant, regardless of the level of environmental control technology employed, 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).



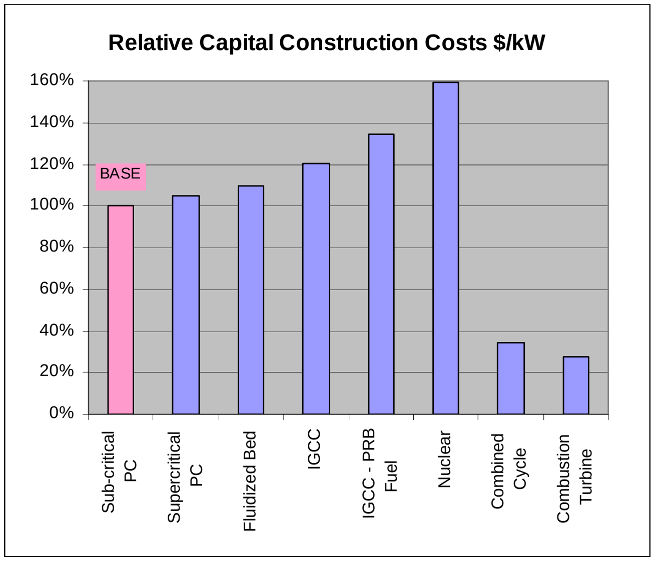


**Seven SE Michigan counties
Are classified as non-attainment for PM2.5**

Technology Price Estimates (2005 Dollars)					
					Design Net Plant
		$/kW		$/MWh	Heat Rate
Technology	Size	Construction	Fixed O&M	Var. O&M	BTU/kWh
Pulverized Coal					
Sub-critical	500	1,370	42.97	1.80	9,496
Supercritical	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 (Cap + O&M)	Bus Bar Costs $/MWh
Pulverized Coal					
Sub-critical	1.25	85%	13.67	27.85	41.53
Supercritical	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 this table were completed in 2004 and are based on the EIA/DOE Annual Energy Outlook 2005, a U.S. Department of Energy and National Coal Council report entitled "Opportunities to Expedite the Construction of New Coal-Based Power Plants"[1] and CNF working group member 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



The above chart 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 then it was to have construction cost estimates developed with a very high level of engineering, which would allow reduced forecast accuracy risk.

Technology Emission Characteristics

Emission rates are shown for a typical plant assuming PRB coal for the PC, CFB and IGCC units. Mercury numbers will need to be developed which will also require an assumed coal source and assumed removal technology.

Plant Typical Emissions (#/MMBTU)					
	SO_2	NOx	Particulate	Hg	CO_2
Pulverized Coal					
Sub-critical	0.10	0.05	0.015	?	200
Supercritical	0.10	0.05	0.015	?	200
Fluidized Bed	0.02	0.10	0.015	?	?
IGCC	0.05	0.05	0.006	?	?
Nuclear	0.00	0.00	0.00	0.00	0.00
Combined Cycle	0.001	0.03	0.00	0.00	120
Combustion Turbines	0.001	0.03	0.00	0.00	120

Major Assumptions and Issues

Plant Retirements

To perform a long-term analysis integrating generation, transmission and demand, the issue of retirement of existing generation assets must be dealt with. Without this consideration the future need for new base load generation will be understated. This is particularly true in Michigan due to the age distribution of existing generation assets.

A general review of age at retirement of Michigan base load 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 of greater than 11,000 BTU/kWh. The low efficiency was the result of the technology of the time where boiler operating pressures were 1,500 psi of less, superheater steam temperature limits were 950 F and systems did not include reheaters or intermediate pressure (IP) turbines.

Since the late-1950’s, the basic thermodynamic design of steam electric generating units has changed little due to metallurgical limits of high temperature steel alloys. In the late 1950’s main steam pressures of 2400 psi with 1000/1000F 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 1950’s 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 working 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 60-year retirement age be used for modeling of coal fired generating units. While it is likely that some will retire sooner than 60 years old and some will retire later, 60-years is a good 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. Major environmental investment required to meet evolving and ever tightening air emission limits on coal fired electric generating units will create additional economic pressure on smaller and older units. The issues of size, age, component replacements and environmental investment will all work against maintaining these units in service. 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 and it now seems that extensions of another 20 years will continue to be granted. This 60-year life is in concert with those 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.

<u>Environmental Issues</u>
Environmental issues are prevalent on two major fronts. Permitting for a new coal fired central generating unit will require addressing a number of critical requirements, many of which are currently uncertain or speculative. Permitting remains uncertain, lengthy and difficult. The other 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 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.

New Source Review (NSR) requirements boil down to either Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) regulations 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 non-attainment 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 regulatory finding that was issued in December 2000 pursuant to Section 112, removing coal and oil-fired electric steam generating units from the CAA Section 112 © source category list. This means coal-fired electric utility steam generating units are a "delisted source category" from Section 112 © and are no longer subject to a MACT regulation. However, in March 2005, the EPA signed two new rules that materially alters future air emissions from power plants. On March 10, 2005 the final Clean Air Interstate Rule (CAIR) was published that will permanently cap emissions of 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 2015. 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.

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, 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 working 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 1980's. 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 a lot of attention recently 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 do not believe this technology is yet ripe for full-scale commercial operation in Michigan.

Gas and oil-fired boilers would 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), 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 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 has to find a greater amount of reductions than what they propose to install. 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.

Summary

The CNF has identified base load generating unit technologies, cost structures and environmental issues that will form the basis for a State wide integrated resource plan (IRP). While IRP 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 1970's, 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.