Wolverine Power Supply Cooperative
Electric Generation Alternatives Analysis
For Proposed Permit to Install (PTI) No. 317-07
For Circulating Fluidized Bed Coal Boilers
at Rogers City, Michigan

Docket Number: U-16000

*Staff Report to Michigan Department of Environmental Quality**

September 8, 2009

*Prepared by staff from the Generation and Certificate of Need Section, Electric Reliability Division of the Michigan Public Service Commission

Table of Contents

Executive Summary

On April 1, 2009, the Commission entered into a Memorandum of Understanding (MOU) with the DEQ that clarified each participant's role and responsibility regarding a review process to evaluate electric generation alternatives and provide technical assistance to the DEQ. The Commission Order in Docket Number U-15958 was issued to clarify the roles and responsibilities of the Commission Staff (Staff) pursuant to the MOU between the Commission and the DEQ related to filings of electricity generating alternatives analyses.

Wolverine Power Cooperative (Wolverine) submitted an Electric Generation Alternatives Analysis (EGAA) to the DEQ and Commission on June 8, 2009. As detailed in their EGAA, Wolverine Power Cooperative is proposing to install new baseload generation that will be comprised of two 300 megawatt (net) circulating fluidized bed (CFB) boilers, for a total of 600 megawatts (MW), and associated facilities at the Carmeuse quarry site near Rogers City.

Staff acknowledges that a generation asset, such as has been proposed by Wolverine, represents a significant financial investment with a variety of associated risks. Significant changes have taken place on many fronts, including a slowing national and state economy, new state policy initiatives on energy efficiency and renewable energy, and pending federal legislation on the regulation of carbon emissions. With these issues in mind, Staff contends that a full spectrum of risks should have been considered within the framework of Wolverine's EGAA as it relates to long-term investment decisions of this nature.

Wolverine's EGAA filing does not constitute an Integrated Resource Plan (IRP), as outlined in 2008 PA 286, should a Certificate of Necessity (CON) be sought. Scenario analyses, using various sensitivities, including a reasonable range of values for the key input assumptions such as capital costs, fuel prices, CO_2 costs, load and energy requirements, were not conducted as part of this analysis.

In accordance with the MOU, Staff reviewed Wolverine's EGAA for the proposed coal-fired electricity generating plant to assess whether energy efficiency, renewable energy, or other alternatives meet future electricity needs. Staff provides the following findings:

- Wolverine failed to demonstrate the need for the proposed facility as the sole source to meet their projected capacity. In particular, long-term purchase power options were not fully explored as part of their analysis. It should be noted that the majority of Wolverine's long-term projected capacity need is based upon the expiration of power purchases (540 MW) on or before December 31, 2011. Wolverine has presented no evidence that the capacity currently supporting this existing contract will be unavailable in the future.
- Staff notes that the proposed CFB plant is one alternative out of a range of alternatives that may be used to fill the projected capacity need. Other alternatives that may fill all or portions of the projected capacity need include; energy efficiency and load management; renewable resources; or a combination of a number of alternatives that could include lesser amounts of purchased power.

- Further given Michigan's current recessionary condition and uncertainty concerning the time frame for recovery, Wolverine's forecasted demand growth of approximately 2.0% appears questionable, or optimistic, and the risk associated with this uncertainty was not fully addressed.

Introduction and Background

DEQ – Commission Memorandum of Understanding (MOU)

On April 1, 2009, the Michigan Public Service Commission (Commission) entered into a Memorandum of Understanding (MOU) with the DEQ that clarified each participant's role and responsibility regarding a review process to evaluate electric generation alternatives and provide technical assistance to the DEQ.

The Commission has two tasks, pursuant to the MOU:

a. Providing technical assistance to the DEQ on all matters related to the need for electric generation in the state, as it relates to the analysis that looks at alternatives to coal-fired generation.

b. Reviewing the alternatives analysis to assess whether energy efficiency, renewable energy, or other alternatives meet future electricity needs.

The MOU between the DEQ and Commission was entered into for the sole purpose of clarifying each agency's role and responsibility regarding the alternatives analysis review and technical assistance for the proposed coal-fired electricity generating plant applications currently pending before the DEQ. The DEQ - Commission MOU is contained in Appendix A of this Staff Report.

Commission Order in Docket Number U-15958

Commission Order in Docket Number U-15958 was issued to establish procedures for the Staff to conduct an alternatives analysis review and to provide other technical assistance to the DEQ pursuant to a MOU between the Commission and the DEQ related to proposed coal-fired electricity generating plants.

Reduced to its essence, the MOU constitutes a clarification of each participant's role and responsibility in satisfying the requirements regarding an alternatives analysis review and the provision of other technical assistance to the DEQ by the Commission related to the DEQ's task of issuing permits in response to applications filed under Part 55, Air Pollution Control of Natural Resources and Environmental Protection Act, 1994 PA 451, MCL 324.101, et. seq., R 336.2817(2), and Section 165(a)(2) of the federal Clean Air Act, 42 USC 7475(a)(2) for authority to construct a new coal-fired electricity generating plant. Commission Order Number U-15958, is contained in Appendix B.

Summary of Proposed Project

Wolverine Power Cooperative (Wolverine) is a not-for-profit, member-owned generation and transmission electric cooperative headquartered in Cadillac, Michigan. Wolverine's four member cooperatives serve homes and businesses in rural portions of 35 counties primarily in northern and western Lower Michigan. Wolverine filed an Electric Generation Alternatives Analysis (EGAA) in the Commission's Docket Number U-16000 on June 8, 2009. Wolverine's EGAA proposes a new facility that will be comprised of two 300 megawatt (net) circulating fluidized bed (CFB) boilers, for a total of 600 megawatts (MW); an auxiliary boiler; a black start turbine generator; an emergency engine generator; an engine fire pump; cooling towers; fuel, limestone, lime, activated carbon, and ash receiving operations; handling and storage equipment; and other ancillary equipment for boiler start-up and plant safety.

Wolverine has stated that the selection of the Rogers City area, and the Carmeuse quarry in particular, was primarily based on the desire to minimize disruption to green space property (the facility requires 1,124 acres plus easements); the space available within the Carmeuse quarry; the distances to nearby residences and structures; the availability of high quality limestone from the Carmeuse quarry for emission controls; and the availability to receive fuel by ship at the Carmeuse port.

Disclaimer regarding Certificate of Necessity (CON) – 2008 PA 286

On October 6, 2008, Governor Jennifer M. Granholm signed into law 2008 PA 286, an amendment to 1939 PA 3. Section 6s of Act 286, MCL 460.6s, provides the option for a utility that seeks to add capacity to its system by construction, renovation, or long-term power purchase to seek one or more certificates of necessity from the Commission. If a utility seeks a certificate of necessity (CON) under this section, it must file an application with the Commission, along with an integrated resource plan.

Section 6s (10) provides that within 90 days of the effective date of the amendatory act, the Commission "shall adopt standard application filing forms and instructions for use in all requests for a certificate of necessity under this section." Section 6s (11) provides that the Commission "shall establish standards for an integrated resource plan that shall be filed by an electric utility requesting a CON under this section."

The issuance and subsequent findings contained in this Staff Report on Wolverine's filing of their Electric Generation Alternatives Analysis (Docket Number U-16000) does not constitute approval or issuance of a certificate of necessity CON by the Commission. Any utility required and/or seeking to obtain a CON must do so in accordance with the rules and procedures set forth under Section 6s (10) of 2008 PA 286 of 2008. Furthermore, the findings contained in this Staff Report are limited to the scope of work described under the MOU between the DEQ and Commission and subsequent Commission Order in Docket Number U-15958.

Technical Meetings

In order to facilitate a thorough review in a relatively short amount of time, Staff scheduled weekly meetings with staff members of Wolverine to discuss questions that arose from the material supplied in the filing. Questions that Staff posed to the utility were submitted in advance (via email or phone calls) in order to properly prepare for productive and efficient meetings. Weekly meetings started immediately after the EGAA was filed and continued through the thirty-day public comment period. Additional meetings were scheduled on an as needed basis through the remaining sixty days of the ninety-day docket period.

In addition, Wolverine also agreed to participate in a technical forum, hosted by the Commission, to provide various environmental groups an opportunity to ask questions about the filed EGAA. Participants included members from the Sierra Club, National Resource Defense Council, Wolverine Energy staff, Commission Staff and DEQ Staff. Attendees were advised to submit questions in advance to Staff to allow representatives from the utility the ability to prepare background information, and to ensure appropriate staff were in attendance and able to respond adequately. Wolverine and their representatives responded verbally to the questions during the Technical Forum. Wolverine's EGAA Technical Forum took place on Monday June 22, 2009 from 2:00pm-4:00pm at the Commission's offices in Lansing, Michigan.

Consideration of Public Comments

Comments from the public were allowed for a period of 30 days and ended on July 9, 2009. All comments that have been submitted within the public comment period were evaluated by Staff and are contained in Order Number U-16000.[1] Questions were sent to Wolverine in regards to public concerns. All written responses to Staff questions are included in Docket Number U-16000. Issues of concern by interested individuals and parties were discussed in detail with the utility in an effort to obtain additional information or clarification. Due to the short amount of time for Staff to prepare a thorough report, comments received by July 9, 2009 were given priority.

Thousands of public comments were received from interested citizens, multiple organizations, and various environmentalist groups expressing their opinion in response to Wolverine's EGAA. Written comments were received by:

International Brotherhood of Electrical Workers, Midwest ISO, City of Cheboygan, Michigan Public Power Agency, County of Cheboygan, Alpena Community College President, Co-Chair of LBWL & Former Attorney General Frank Kelly, Michigan Infrastructure & Transportation Association, National Rural Utilities –Cooperative Finance Corporations, Congressman Stupak, Michigan Economic, Development Corporation, Pulawski Township Board of Trustees, City of Rogers Planning Committee, City of Rogers City Community Development Authority, Presque Isle County Board of Commissioners, City of Rogers City, Rogers Township board of Trustees,

[1] For a list of all public comments posted to the PSC e-docket, refer to; http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=16000

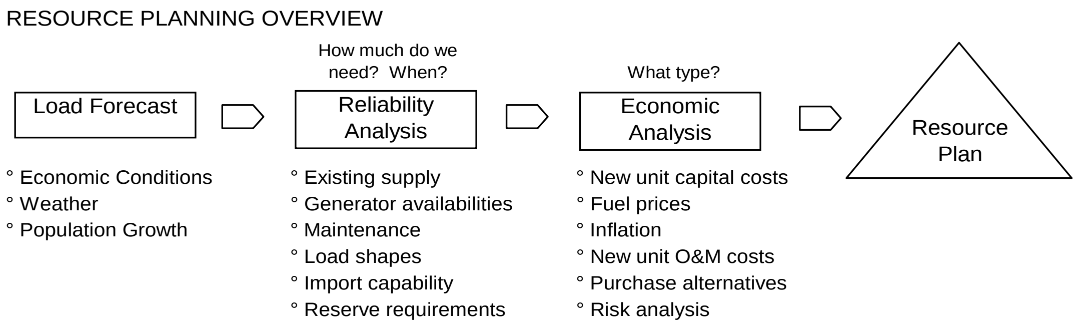
IBEW 6th District, Midwest Energy Cooperative, Bluewater Wind LLC, Environmental Law & Policy Center, Great Lakes Environmental Law Center, Howard & Howard Attorneys PLLC, and Sierra Club members (nearly 3,200 individual comments), and many other citizens.

In addition to the public comments received, numerous exhibits were included to support positions. Wolverine also provided a press release regarding Wolverine's distribution members experiencing sustained peak levels in 2009, the response to staff questions during the comment period and a letter regarding the Midwest ISO Independent Market Monitor's State of the Market Report.

Regional Resource Adequacy

Planning for Reliability

For many decades, electric utilities have been planning to meet the forecasted needs of their customers. The figure below outlines the elements of a typical utility resource plan.



For several decades utility resource planning has been directed towards answering the following traditional questions:

- Build versus buy?
- What is the best mix of baseload, intermediate, and peaking resources?
- What is the cost to my customers, and what is the rate of return for my shareholders?

In recent years, utility planning has become more complex and must address some new challenges and risks[2]:

- Am I operating in a regulated or deregulated market?
- Given the recent volatility in gas/oil prices, what type of resource should be considered (i.e., gas, coal, nuclear, renewable, or fixed price)?
- Does the resource satisfy installed capacity requirements?
- Is there regional coordination of planning to consider?
- Am I affected by Renewable Portfolio Standard (RPS) mandates?
- How will the new Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and carbon regulations affect my power supply decision?
- Where does demand-side management economically fit in to the portfolio?

[2] Ventyx, Resource Evaluation, Planning, and Reliability Services, http://www1.ventyx.com/advisory/irp-rfp.asp.

Staff expects that utility plans filed today will address a full spectrum of risks as outlined above. While individual utilities must assess the reliability of their own supply to meet their projected loads and individual requirements, similar assessments may be completed at the state level and at the regional level that provide insight into the resource adequacy and future resource plans of the broader region in which the utility operates.

Regional Grid Operation

The Midwest ISO is an independent system operator that was established in 1998 and approved by FERC to be the nation's first regional transmission organization in 2001. The Midwest ISO is the reliability coordinator in our region and it manages the real-time power flow throughout the region twenty four hours per day, seven days per week. In addition to reliability coordination, the Midwest ISO also operates a day-ahead market, a real-time energy market, an ancillary services market, and a financial transmission rights market. The energy markets are operated using a security constrained economic dispatch. The Energy Policy Act of 2005 (EPAct 2005) defines economic dispatch to mean "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[3] [EPAct 2005, Sec. 1234 (b)]

EPAct 2005 also directed that an "Electric Reliability Organization" (ERO) be formed to develop and enforce mandatory electric reliability standards for the bulk power system in the United States. In 2006, the North American Electric Reliability Council (NERC) was approved as to be the ERO for the U.S. EPAct 2005 directs the ERO to "conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America." [EPAct 2005, Sec. 215 (g)] NERC designates some regional responsibilities to Regional Entities such as Reliability*First* Corporation (RFC) and the Midwest Reliability Organization (MRO), including the development of regional long-term resource assessments. The electric reliability standards enforced by NERC and the Regional Entities are mandatory and non-compliance with the standards may result in significant financial penalties.

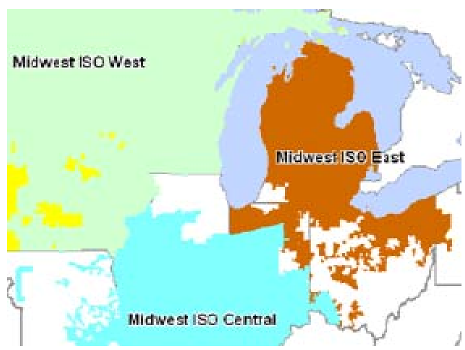
RFC's regional reliability Standard BAL-502-RFC-02,[4] Planning Resource Adequacy Analysis, Assessment and Documentation directs the methods and frequency for conducting assessments of resource adequacy in the RFC territory. MRO has a similar standard for resource adequacy assessments as well. The Midwest ISO serves as the planning coordinator in our region and conducts resource adequacy assessments to meet the regional reliability standards set forth by RFC and MRO. In addition to adequacy assessments, FERC approved changes to the Midwest ISO transmission and energy markets

[3] Economic Dispatch of Electric Generation Capacity, U.S. DOE, http://www.oe.energy.gov/DocumentsandMedia/final_ED_03_01_07_rev2.pdf, p. 2.
[4] Standard BAL-502-RFC-02, 12/4/08, http://www.rfirst.org/Documents/Standards/Approved/BAL-502-RFC-02.pdf.

tariff in 2009 to include reserve margin requirements that are specified as "an individual LSE reserve level of 12.69%"[5] for the summer of 2009.

Adequacy in the Midwest ISO East Sub-Region

The Midwest ISO Independent Market Monitor (IMM), Dr. David Patton of Potomac Economics, annually delivers a State of the Market Report (SOM) which includes details that provide insight with regard to the resource adequacy of our region. The IMM's recently released 2008 SOM, states that "Although the system's resources are adequate for the summer of 2009, new resources will be needed over the long-run to meet the needs of the system." [6] More specifically, the IMM indicates that the Midwest ISO East Region has the tightest reserve margins in all of Midwest ISO for all cases analyzed.[7]



The Midwest ISO East region includes the majority of Lower Michigan and a small part of northern Indiana and northern Ohio. The SOM reports reserve margins for the Midwest ISO East Region from a high of 22.5% of nameplate capacity for 2009, down to 3.5% of high-temperature capacity[8] excluding interruptible load and behind the meter generation. It should also be noted that 11.4% reserve margin for high temperature capacity that includes existing interruptible load and behind the meter generation is below the current Midwest ISO Module E tariff requirement of 12.69% planning reserve margin that is required for Midwest ISO load-serving entities for 2009, and the 12.69% requirement is likely met through utilization of capacity resources from neighboring regions.

[5] Midwest Independent System Operator 2009 – 2010 LOLE Study Preliminary Report, http://www.Midwestmarket.org/publish/Document/1d44c3_11e1d03fcc5_-7df00a48324a/Midwest%20ISO%202009-2010%20LOLE%20Executive%20Report.pdf?action=download&_property=Attachment.

[6] 2008 Midwest ISO IMM's State of the Market Report, http://www.Midwestmarket.org/publish/Document/6ef35b_121e89707ed_-7dcf0a48324a/2008%20Midwest%20ISO%20State%20of%20the%20Market.pdf?action=download&_property=Attachment, 6/26/09, p. 55.

[7] 2008 Midwest ISO IMM's State of the Market Report, p. 56.

[8] High-temperature capacity refers to derates of capacity during high temperature periods.

Adequacy in the ReliabilityFirst Region

Reliability*First* (RFC) is a Regional Entity enforcing North American Electric Reliability Council (NERC) reliability standards. While a portion of Michigan's Upper Peninsula is within the Midwest Reliability Organization's (MRO) footprint, the RFC footprint includes a majority of Michigan[9]:

Long Term Assessments of electric demand and supply are required by NERC standards. RFC's October 2008 Long Term Resource Assessment projects an increase of 24,500 MW in net internal demand for the entire region from 2008 - 2017, and an increase in net summer capacity of 16,100 MW for the same ten year time period.[10] Although RFC is projecting that demand growth will continue to outpace supply growth over the next ten years, RFC does project that reserve margin requirements will continue to be met throughout the study period. RFC reports that "maintaining the overall reliability of the Reliability*First* Region could be challenged by such factors as:

- Potential environmental regulations & emission control systems
- Aging Generating Units"[11]

Planned Generation in the Midwest ISO Region

As new generation is proposed, interconnection studies are performed in order to determine the scope of transmission upgrades that may be necessary in order to accommodate the proposed generation. Generation planners submit interconnection requests to the regional transmission operators, such as the Midwest ISO and they are placed in an interconnection queue. Current[12] active interconnection requests in the Midwest ISO queue[13] include:

[9] RFC Region Map, http://www.rfirst.org/MiscForms/AboutUs/Territory.aspx).
[10] 2008 RFC Long Term Resource Assessment, October, 2008, http://www.rfirst.org/Documents/Reliability/Reports/2008%20RFC%20Long%20Term%20Resource%20Assessment.pdf, p. 2.
[11] 2008 RFC Long Term Resource Assessment, October, 2008, p. 2.
[12] Current active interconnection requests as of 7/27/09, including projects that are not in "parked" status.
[13] Midwest ISO Interconnection Queue, http://www.Midwestmarket.org/page/Generator+Interconnection.

Proposed Generation Type	Total Midwest ISO (Nameplate MW)	Total Michigan (Nameplate MW)
Coal	2693	600[14]
Nuclear	3405	1563
Gas / Diesel / Co-gen	1655	0
Wind[15]	45671	1549
Other Renewables	485	101

In Michigan, there are currently three baseload generators in the Midwest ISO interconnection queue. They include Wolverine's Rogers City coal-fired CFB proposal, Consumers Energy's Karn-Weadock advanced supercritical pulverized coal plant proposal, and Detroit Edison's Fermi 3 nuclear plant proposal. This electric generation alternatives analysis is dealing specifically with Wolverine's Rogers City proposal.

Planning in Michigan

Michigan has recently developed long-term resource adequacy plans for the state. The Commission commenced the Capacity Needs Forum[16] in October 2004 to assess the adequacy of resources to meet the long-term electric needs in Michigan. Shortly following, Governor Granholm issued E.D. 2006-2 which called for the development of a comprehensive plan for meeting the state's electric power needs. The 21st Century Energy Plan[17] (21st CEP) was issued in response to the E.D. on January 31, 2007. Since the release of the 21st CEP, Michigan has enacted 2008 PA 295 and 2008 PA 286. 2008 PA 295 outlines requirements for renewable energy and energy optimization within the State of Michigan. Another key change since the 21st CEP has been the continued downturn in the Michigan economy which has generally lowered utility forecasts in Michigan. Electric plans from Michigan companies developed since the enactment of 2008 PA 295 should reflect the requirements outlined in the Act, and should also include updated forecasts, costs, and assumptions as compared to previous plans.

Wolverine Power Cooperative - Load Forecast Evaluation

Wolverine's demand forecast predicts 2.5% growth in residential sales and 2.1% growth in C&I sales throughout the forecast period. Historically, Wolverine's total electricity sales have grown at an annual compound rate of 3.9% since 1990, more than twice the rate of growth in electricity usage reported for the entire State of Michigan. Continued growth is

[14] The 600 MW listed is for Wolverine's Rogers City proposal. Consumers Energy also has a Karn-Weadock proposal for 875 MW of coal in Michigan in the Midwest ISO queue, however, it is currently in "parked" status. The "parked" status is a temporary holding pattern and parked projects may still proceed forward through the interconnection queue process at a later date.

[15] New Wind resources in the Midwest ISO are credited with 20% of nameplate capacity on-peak for installed reserve requirements, whereas coal, nuclear, and gas-fired units are typically credited with 100% of nameplate capacity on-peak for installed reserve requirements.

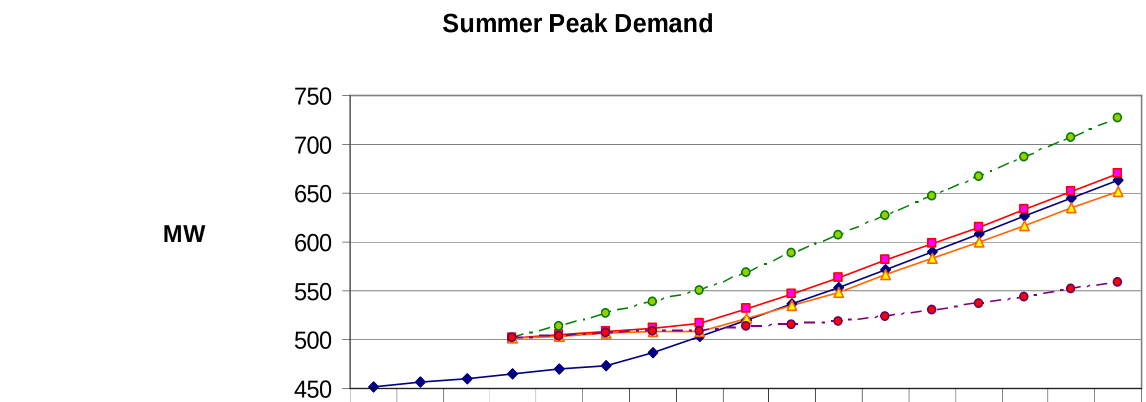
[16] MPSC Capacity Needs Forum, http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/index.htm.

[17] 21st Century Energy Plan, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm.

expected to be driven by increasing number of end-use customers, growth in the use of energy per end-use customer, and increasing use by C&I customers.

Wolverine acknowledged that there is uncertainty in future demand growth by analyzing both low-growth and high-growth sensitivities. Figure 1[18] depicts Wolverine's current forecasts[19] compared to its 21st CEP base case prediction.[20]

Figure 1



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
21st CEP Base Case	451	456	460	465	470	474	487	504	520	537	554	572	590	608	627	645	663
EGAA Base Case w/out EO				502	505	508	512	516	531	547	564	581	598	615	633	651	670
EGAA Base Case				502	504	506	508	509	522	535	549	566	583	600	617	635	652
High Growth Scenario				502	514	526	538	550	569	588	607	627	647	667	687	707	727
Low Growth Scenario				502	504	506	508	509	513	515	518	524	530	537	544	551	559

Wolverine's EGAA base case forecast includes the expected effects of its distribution members'[21] 2008 PA 295 energy optimization (EO) programs. Distribution member programs include continued installation of Advanced Metering Infrastructure (AMI) systems, and customer educational initiatives such as energy audits.[22] In 1992, Wolverine installed a load management (LM) system which focused on direct load control of its winter peak demands. In recent years Wolverine has experienced shifts in peak demand from winter to summer. Wolverine's efforts towards energy optimization include revamping of this system to allow for communication with its distribution members' AMI systems and summer peak direct load control.[23] For purposes of its EGAA, Wolverine has assumed a

[18] Wolverine's EGAA presents a 2008 peak demand (502 MW) that has been weather-normalized to account for cooler than normal summer temperatures in 2008. Actual 2008 peak demand was 461 MW.
[19] In order to compare Wolverine's EGAA forecast with that from the 21st Century Energy Plan (CEP), Staff has excluded expected load served to alternative electric suppliers (AES) as presented in the EGAA.
[20] The following link identifies the CNF Update web page: http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/cnfupdate/cnfupdate.htm
[21] Wolverine's current distribution members are Cherryland, Great Lakes, HomeWorks and Presque Island cooperatives.
[22] Wolverine EGAA, pg. 40
[23] Wolverine EGAA, pg. 39

demand reduction of 15 MW by 2015 and 18 MW by 2021.[24] This represents roughly 2.7% of it's peak load in 2021. Including efficiency gains, Wolverine's base case forecast predicts an annual compound growth rate of 2.03%.[25]

Wolverine's expectations of "uncontrolled[26]" demand have changed since the 21st CEP. Figure 1 depicts Wolverine's base case growth without the expected impact from energy optimization. Wolverine's 21st CEP forecast estimated an annual compound growth rate of 2.77% from 2008 to 2021. Its EGAA forecast, net of any EO or LM, estimates 2.25% growth over the same time period. Figure 1 depicts how Wolverine's 21st CEP base case forecast predicts roughly 2.3% peak demand growth from 2008 to 2012. Wolverine's EGAA base case (without EO) forecast has revised growth over this same period to downward to 1.01%.. On high-level, this downgrade in expected growth through 2012 indicates that Wolverine has considered Michigan's current recessionary condition. Following 2012, The EGAA base case follows a similar trajectory as the 21st CEP predictions. Wolverine's base-case forecast assumed that its distribution members' are experiencing a recession rather than a structural downgrade in local economies.

Comments received indicated that Wolverine used "stale data" and that "the underlying economic forecasts did not reflect current economic conditions."[27] Wolverine utilized data from Woods & Poole Economics and the National Planning Association that was released in December 2008, and May 2008 respectively. The data collection process and analysis process to develop such data takes several months; sometimes two years. The inherent lag time between the data collection and the release of these forecasts suggests a possibility that the economic assumptions underlying Wolverine's forecasts do not fully reflect the extent of the recession in the local and national economies.

Figure 1 also depicts how Wolverine has considered low growth and high growth sensitivities.[28] While both alternatives incorporate the expected effects from the 2008 PA 295 efficiency programs, their economic expectations represent fundamentally different long-term outcomes. The high growth sensitivity equates to the assumption that Michigan's current recession will behave similar to the 1980 to 1982 recession[29] with a strong long-term rebound beginning in 2010. The low growth sensitivity equates to the assumption that their service territories are experiencing a structural economic shift which will result in long-term growth rates significantly below the base case.

[24] Wolverine EGAA, pg. 27
[25] These annual compound growth rates were calculated from the data table represented in Figure 1. They do not include any expected growth in AES load.
[26] Staff uses the term "uncontrolled" to indicate peak demand that has not been reduced from any energy optimization programs. This data set was included to help Staff determine how Wolverine has evolved its view of its service territories' economic and demographic behaviors since the 21st CEP.
[27] Comments of the Environmental Law and Policy Center, 7/30/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0112.pdf, p. 4.
[28] Figure 1only depicts Wolverine's High and Low growth sensitivities. In its EGAA, Wolverine also considers two additional scenarios including one which considers the addition of a new distribution member. This latter scenario results in a 778 MW peak demand by 2021.
[29] Wolverine EGAA, pg 30

Internal-Assessment of the Forecasting Models

Each distribution member's forecast is a direct output of a combination of separate regression models for each customer class[30]. Various demographic, economic and weather variables were themselves forecasted and used as inputs into their models.[31] The base case distribution members' residential and seasonal customer models[32] forecast a 2.0% annual compound growth in customers in the next fifteen years compared to 2.5% growth in past fifteen years.[33] This continued growth is driven by expected housing starts. These models also predict that electricity use per customer will grow at an average annual rate of 0.5% throughout the next fifteen years compared to 0.6% in the past fifteen years.

Wolverine's distribution members have three subclasses of commercial and industrial (C&I) customers with distinct sales growth histories and prospects.[34] Non-Oil Individual C&I loads represent currently roughly 50% of Wolverine's total C&I sales demand[35] and have experienced annual growth rates of 8.4% over the past ten years. Forecasts for these customers were developed through a combination of specific business plans and econometric estimation. This customer class is projected to grow at an annual rate of 3.9% over the next 15 years. Oil and Gas customers represent roughly 10% of Wolverine's total C&I sales demand and have experienced an annual growth rate of 2.0% over the last ten years. Sales to this class of customers are highly dependent on oil prices and the remaining quantity of local oil and gas reserves. Wolverine's model forecasts that this sales class will grow at an annual rate of 0.7% over the next ten years. The last C&I customer class, General Commercial Loads, represents about 40% of Wolverine's total C&I sales demand and have seen 6.6% annual growth throughout the past ten years. Separate regression models for this customer class were developed for each distribution member and then aggregated to project future growth for this class as a whole. Indicators such as population growth, lagged electricity consumption and retail sales[36] were used to project growth for this customer class. In total, Wolverine projects that General Commercial Loads will grow at a 2.9% annual growth rate over the next ten years.

Wolverine's peak demand model is a summation of individual peak demand models for each of its distribution members. These models are dependent on the quantity of energy sales expected during any month, the expected peak temperature at the time of peak demand and the level of air-conditioning (A/C) saturation. In response to Staff questions regarding the basis for predicted A/C saturation growth, Wolverine submitted saturation

---

[30] Wolverine's EGAA breaks down commercial and industrial customers into three separate classes. Non-Oil Individual C&I Loads are forecasted based on specific business plans.

[31] Wolverine relied on Woods and Poole Economics, Inc and the National Planning Association for economic and demographic data. In cases where both consultants provided the same data, i.e. county population growth, the average of these two data sets were calculated and used as inputs into their regression models.

[32] Cherryland's seasonal class historic usage was combined with its residential class for development of a single model. Other distribution members used separate models for seasonal and residential customers.

[33] At Wolverine's request, Staff was asked to review their detailed load forecast report at the law offices of Dykema Gosset in downtown Lansing, MI. The full report was provided to Wolverine by Power Systems Engineering. Power System's forecasters were made available to Staff for questioning.

[34] Wolverine EGAA, pg. 15

[35] Information on Wolverine's C&I customers was taken from Table 2.3 and pgs 16-20 of their EGAA.

[36] Here "retail sales" refers to business sales outside the electric industry.

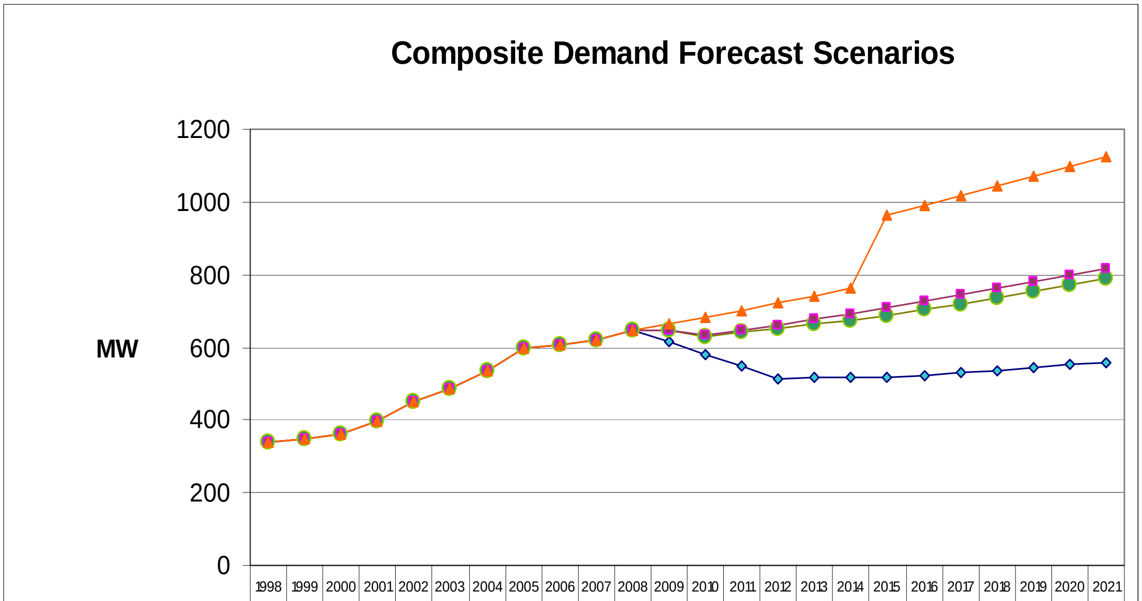
data from a 2007 Customer Survey.[37] This, in combination with previous surveys, identified that Wolverine's central A/C saturation levels have increased from 3.3% in 1987 to 34.8% in 2007 compared to a U.S. average of 59.3% in 2005. A key underlying assumption in Wolverine's peak demand predication is that central A/C saturation levels in its territory will continue to approach the U.S. average as they have historically done so.

Wolverine's Composite forecast represents distribution member load in addition to load demand from its two alternative electric supplier (AES) customers, Wolverine Power Marketing and Spartan Renewable. In 2008 their combined peak demand was 146 MW, roughly 23% of that year's weather-normalized total demand.

Figure 2[38] depicts multiple demand sensitivities that Wolverine developed to assess the impact of uncertainty in future demand on future resource needs. Wolverine's High Growth scenario assumes it will (1) experience load requirements consistent with a strong economic recovery, (2) continued growth in its AES customers' sales, (3) an increase in gas compression load and (4) the addition of Midwest Energy Cooperative as a new member in 2015. Wolverine's Low Growth scenario assumes that (1) its service territories' economies are experiencing a structural shift instead of a temporary recession, (2) load growth from its AES customers declines to zero, (3) no growth in gas compression load and (4) no new Midwest Energy membership. Both scenarios factor the expected effects of the previously mentioned energy optimization programs.

[37] Wolverine's Response to Staff Questions, 6/23/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf, p. 1.
[38] Figure 2 uses data from Wolverine's original EGAA as well from its additional filings during the review process. Base Case and Base Case without Energy Optimization scenarios represent Wolverine's submitted data from filing 023 in the Commission's E-Docket system, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf.

Figure 2



	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Low Growth	337	346	360	396	450	487	535	600	608	620	648	615	581	548	515	516	517	518	524	530	537	544	551	559
Base Case	337	346	360	396	450	487	535	600	608	620	648	646	631	641	652	663	675	688	704	720	737	754	771	790
Base Case w/out EO	337	346	360	396	450	487	535	600	608	620	648	647	634	647	662	677	693	710	727	744	761	779	797	816
High Growth	337	346	360	396	450	487	535	600	608	620	648	666	683	700	721	742	764	964	991	1017	1044	1070	1097	1123

Key Observations

Staff notes that Wolverine's development and application of its forecasting models are consistent with general statistical practice. However, given Michigan's current recessionary condition and the uncertainty surrounding its recovery, Staff questions the base-case indicator variables themselves. State-wide estimates of unemployment in Michigan have been increasing nearly every fiscal quarter and now top 15%.[39] With state-wide population on the decline, Wolverine's forecasted demand growth of 2.0% appears questionable, or optimistic, and hence the risk associated with the uncertainty in the forecast must be fully addressed. Staff notes that Wolverine's service territories represent structurally different economies than those of the major investor-owned utilities in Michigan. Furthermore, its distribution members' service territories are largely rural in nature. Due to urban congestion, any housing development that does occur is more likely to occur within more rural service territories. Although the demand growth for the State of Michigan overall has declined in recent years and may continue to decline in the coming years, it is not unreasonable to expect that there may be pockets within the state that will continue to have positive load growth based upon differences between specific local territories.

With respect to its peak demand, Staff questions Wolverine's underlying assumption that its central A/C levels will continue to approach the U.S. average. Historical growth in this saturation presented by Wolverine does provide evidence that growth will continue, however it does not provide reliable evidence regarding its equilibrium level of saturation. This base case assumption, along with predicted population growth, carries planning risks

[39] As of 7/15/09, DELEG estimates 15.2% state-wide unemployment.

that must be addressed. Wolverine addressed the risk associated with uncertainty in the forecast by developing sensitivities in future demand, which are shown in Figure 2.

As is common in load forecasting, Wolverine's base case models assume fixed values for its indicators. In reality, these indicators are themselves estimates and therefore are embedded with uncertainty. This necessary adaption limits the quality of risk measurements traditionally provided by calculated confidence intervals.[40] The alternative scenarios Wolverine adopted for purposes of its resource plan represent adequate estimates of where the upper and lower bounds of future peak demand may fall. Figure 2 shows that Wolverine expects to experience 2021 peak demand anywhere between 559 MW and 1123 MW. While this represents a large range of possibilities, the risk associated with the uncertainty in the forecast must be fully addressed.

Wolverine Power Cooperative - Resource Needs Evaluation

Resource Adequacy Planning, as described by Wolverine's EGAA "is focused on assuring that real, physical generation is identified somewhere in the Midwest supply chain, to ensure that electric demands can be served on any given day, especially the highest demand days.[41]" Essentially, resource adequacy planning is planning for reliability. Load-serving entities in the Midwest ISO region are required to meet the requirements of the Midwest ISO's transmission and energy markets tariff.

Wolverine's resource adequacy calculation and projected resource needs for the base case are shown in the EGAA.[42] Inputs into the resource adequacy calculation include the internal peak demand that has been reduced based upon peak impacts from energy efficiency and demand response, along with interruptible demand, the reserve margin, owned generation, capacity purchases and capacity sales.

The load forecast was described in the previous section, and Wolverine's base case forecast included the energy efficiency requirements specified in 2008 PA 295 through 2015 with lesser amounts after 2015. Wolverine has also assumed 20 MW of interruptible load which is subtracted from the peak demand before applying the reserve margin. Wolverine assumed a reserve margin of 13% which is very close to the Midwest ISO Module E requirement of 12.69% for the summer of 2009.

Wolverine currently owns a 16 MW share of Campbell 3, and 202 MW of natural gas peaking units[43]. Wolverine has a 20-year contract for 52 MW with the Harvest Wind Farm, and in 2008, Wolverine included an additional 540 MW of purchased power in its supply

---

[40]Veall, Michael R. *Bootstrapping the Probability Distribution of Peak Electricity Demand,* International Economic Review, vol. 28, no. 1,Feburary 1987, pp. 203-212
[40] MetrixND supporting documentation, "Appendix B: Statistics Available in MetrixND" pp 208-209. This documentation includes reference to the following scholarly paper:
M. Feldstein *The Error of Forecast in Econometric Models When the Forecast Period Exogenous Variables are Stochastic,* Econometrica, vol. 39, pp. 55-60, January, 1971
[41] Wolverine EGAA, p. 45.
[42] Wolverine EGAA, Table 4.4, p. 50.
[43] Wolverine's owned generation and capacity purchases are outlined in section 4.2 of their EGAA, pp. 42 – 45.

portfolio. Wolverine has a purchased power agreement with Detroit Edison which "is sourced through a mix of the company's assets"[44] and is set to expire at the end of 2011. Wolverine's EGAA shows the results for resource adequacy calculations for the base case, as well as the high growth and low growth cases.

Wolverine's Resource Adequacy Scenarios[45]			
	Remaining Capacity Requirements MW		
	2012	2015	2021
Base Case	485	526	641
High Growth	563	837	1017
Low Growth	330	334	380

Wolverine's EGAA contends that it has a need for 526 MW of resources in 2015 for the base case assumptions. Wolverine's resource adequacy scenarios quantify the total resource needs to meet peak load with sufficient reserves in order to ensure reliable service and keep the lights on, based upon Wolverine's assumptions. The next step in electric infrastructure planning is to determine what type of capacity is needed in order to meet the total load demand for all hours at the least cost.

Wolverine Power Cooperative - Resource Planning Methodology

Wolverine's Least Cost Planning (LCP) Approach

In order to evaluate the various alternatives available to meet resource needs, Wolverine employs "Least-Cost Planning" to achieve a least-cost optimum portfolio of resources for its member-owners. Wolverine's Least-Cost Planning (LCP) methodology employs screening curves which are used to compare the costs of various types of generation along the range of utilization factors.

Wolverine's EGAA[46] shows the screening curve results for the base case scenario. The base case screening curve shows the following least-cost optimal choices for utilization ranges:

Utilization Range (approximate)	Least-Cost Optimal Choice
< 25%	Peaking
25% < 58%	Intermediate
> 58%	Baseload

As shown in the example on page 49 of the EGAA, Wolverine determines the appropriate quantity of each type of resource by finding the utilization points from the screening curve on the load-duration curve. Wolverine's EGAA[47] tabulates the results showing the

[44] http://efile.mpsc.cis.state.mi.us/efile/docs/16000/0023.pdf, p.12.
[45] Wolverine EGAA, p. 51
[46] Wolverine EGAA, Figure 4.6, p. 57.
[47] Wolverine EGAA, Table 4.10 and 4.11, p. 56.

breakdown of capacity needs for baseload, intermediate, and peaking capacity for each scenario that was evaluated for the year 2015 and the year 2021.

Modeling results are based upon the input assumptions that went into the development of the screening curves, and the base case fuel cost screening curve assumptions are shown in Wolverine's EGAA.[48] Assumptions are included for installed costs, heat rates, fuel prices, fuel cost, O&M, plant life and the cost of capital for peaking units, intermediate units and for baseload. The assumption for the installed cost of baseload generation is listed at $2200/kW, and the EGAA states that "the baseload values reflect inputs specific to the technology proposed by Wolverine for construction at Rogers City site. Specifically, these Circulating Fluidized Bed (CFB) units are fueled by a blend of Powder River Basin Coal and petroleum coke."[49] Additionally, Appendix A-4 states that "the EPC costs for the coal fired plants were developed from built-up estimates, which included some equipment quotes and calculated material quantities."[50]

Several comments asserted that Wolverine has substantially underestimated the construction costs for a new CFB facility. In comments filed, Synapse Energy Economics states "it would have been more reasonable for Wolverine to use a CFB coal plant cost of $3,500 per kW to $3,800 per kW in its economic analyses."[51] Wolverine's Appendix A-2 is a study conducted by Burns and Roe Enterprises that compares coal-fired alternatives for the proposed Rogers City site. Burns and Roe estimates a CFB capital cost for Rogers City at $2484/kW in 2006 dollars. Wolverine did not provide supporting evidence as to the use of the lower $2200/kW for the capital cost in their analyses as opposed to an escalation of the $2484/kW by its consultant.

For the base case, Wolverine assumed $7.99/MMBtu for natural gas, $2.22/MMBtu for powder river basin coal, and $1.53/MMBtu for petroleum coke. Wolverine's fuel price projections are based on the year 2015 because 2015 is the year that was used for their least-cost planning screening analysis.

Assumptions for future fuel prices have inherent uncertainties and may have significant impacts on the modeling results. In order to capture some of the uncertainty surrounding future fuel prices, Wolverine analyzed alternative scenarios. For each of the load forecast scenarios considered, the base case, the high-growth scenario, and the low-growth scenario, Wolverine analyzed a base fuel cost scenario, a high fuel cost scenario, a low fuel cost scenario, and a carbon tax scenario. The high and low-end estimates for fuel prices that Wolverine uses for this screening process representing the year 2015 are shown:

[48] Wolverine EGAA, Table 4.6, p. 52.
[49] Wolverine EGAA, p. 52.
[50] Wolverine EGAA, Appendix A-4, p. A4-7.
[51] Synapse Energy Economics Comments, 7/8/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0063.pdf, p.7.

	Lower Bound	Upper Bound
PRB Coal ($/MMBtu)	1.20	4.56
Midwest Pet coke ($/MMBtu)	1.00	4.00
Natural Gas ($/MMBtu)	6.15	13.40
Carbon Tax ($/ton)	0	42.14

In order to evaluate the potential impact of a carbon constrained future, Wolverine modeled a carbon tax scenario. "As a conservative analysis, Wolverine evaluated a Carbon Tax scenario as a tax with no offsets or allowances. Current legislation under discussion contemplates emissions allowances that would be provided into the market based upon various criteria. These allowances would lessen the impact of the carbon costs indicated in this scenario."[52] Wolverine assumed $42.14/ton CO_2 in the carbon tax scenario for 2015, and zero cost for CO_2 in all of the other screening scenarios. Wolverine's assumption for the future price of carbon was challenged by public comments as being too low even though Wolverine contends that it is a conservative assumption because there are no offsets or allowances included in its assumption. Staff notes that while there is significant uncertainty over the future price of carbon, the planning methodology would have benefitted from analyzing a range of potential carbon scenarios over a longer term planning period such as twenty years.

Within the carbon tax scenario, Wolverine also increased the price of natural gas by 25% from $7.99/MMBtu to $9.99/MMBtu based upon the assumption that CO_2 legislation will increase the demand for natural gas leading to increased fuel prices. Synapse Energy Economics disagrees with Wolverine's assumption to increase the price of natural gas in its carbon tax scenario and states that "Wolverine's assumption of a very high natural gas price in its Carbon Tax Scenario biases its cost analyses in favor of a coal alternative."[53] While Staff agrees that higher natural gas prices could help tip the scales in favor of a coal alternative, the assumption of $9.99/MMBtu is still significantly lower than Wolverine's assumption for natural gas in the high fuel cost scenario of $13.40/MMBtu. Although Wolverine's assumption of the increased natural gas price seems to be within a reasonable range of future possibilities, Staff agrees with public comments asserting that the scenario analysis would have been more robust if additional fuel price sensitivities were modeled with the carbon tax, as opposed to a single set of fuel price assumptions with the carbon tax.

While Wolverines' fuel and carbon costs represent relatively conservative estimates through 2015, the price intervals are highly contentious when extended out over a longer-term planning horizon. The assessment of cost risk cannot be fully addressed without considering long-run trends in fuel and carbon prices

Several comments received criticized Wolverine's LCP analysis because it did not include energy efficiency, wind, other renewable resources, or energy purchases that could be included in portfolios of alternatives to the proposed Rogers City project. While the EGAA filing submitted by Wolverine did not include energy efficiency or renewable resources in

[52] Wolverine EGAA, p. 53.
[53] Synapse Energy Economics Comments, 7/8/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0063.pdf, p.18.

the LCP analysis, Wolverine did respond to Staff's questions on that subject stating that "Section 6 of Wolverine's Alternatives Analysis describes potential technologies, renewable and otherwise, that could be utilized to supply this baseload need."[54]

Wolverine did provide updated screening curves that show wind plus natural gas generation[55] stating that "the wind must be combined with natural gas combustion turbine(s) as a backup to provide the necessary baseload supply."[56] Wolverine assumed a 30% capacity factor for wind, an installed cost of $2500/kW, a variable O&M cost of $1.00/MWh, and a zero cost of fuel. Given the assumptions, the screening curves show that wind plus natural gas backup would not be selected as the least-cost option at any utilization percentage, because the curves for baseload, intermediate, and peaking generation are still lower-cost at all points on the screening curve.

Staff then requested that Wolverine provide another set of updated screening curves showing renewable or renewable plus natural gas backup that include carbon costs. Wolverine provided the updated screening curves[57] showing wind plus natural gas backup along with the assumptions from the carbon tax scenario. Including the carbon tax assumption, the screening process shows that wind plus natural gas would not be chosen as the least cost option at any utilization percentage, given the assumptions.

Wolverine's EGAA tabulates the LCP analysis results for the years 2015, and 2021 for all of the scenarios considered.[58] The amount of baseload generation needed for the base case load scenario results are as follows:

Wolverine Least-Cost Planning Base Case Load Scenario	Baseload Capacity Needed – 2015 (MW)	Baseload Capacity Needed – 2021 (MW)
Low Fuel Cost Scenario	414	516
Base Case Fuel Cost Scenario	433	535
High Fuel Cost Scenario	458	560
Carbon Tax Scenario	414	516

Considering the low-growth and high-growth scenarios, the baseload portion of Wolverine's resource needs range from a low of 263 MW to a high of 678 MW in 2015, and from a low of 285 MW to a high of 893 MW in 2021. Wolverine contends that "the results of the Least-Cost Planning analysis shows an imminent need for a large amount of baseload generation. With the exception of an unlikely future fuel scenario where natural gas prices drop and remain at an extremely low level, Wolverine needs significant baseload generation under all considered futures. This holds true for a future that includes a cost applied for the emission of carbon."[59]

[54] Wolverine Response to Staff questions, 6/23/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf, p. 17.
[55] Wolverine Response to Staff questions, 6/23/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf, p. 18.
[56] Wolverine Response to Staff questions, 6/23/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf, p. 17.
[57] Wolverine Response to Staff questions, 7/9/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0090.pdf, p. 3.
[58] Wolverine EGAA Table 4.10 and 4.11, p. 56.
[59] Wolverine EGAA, p. 61.

While Wolverine's forecast of carbon, coal and natural gas represent supportable projections, its least cost planning screening analysis, which looks at a snapshot of projections in the year 2015, does not address the risk of price changes over time. Wolverine performed a 20-year levelized busbar analysis that considered an escalation of fuel prices through the 20-year period.

Wolverine's 20-year Levelized Busbar Analysis

Following the Least-Cost Planning analysis, Wolverine studied the suitability of several traditional and alternative lower emitting technologies to meet the identified resource needs. Those alternatives that Wolverine deemed commercially available, technically feasible at the Rogers City site, and suitable for baseload operations have 20-year levelized busbar costs in cents / kWh provided. Wolverine's EGAA lists the following alternatives to the proposed Rogers City CFB plant[60]:

Alternatives Evaluated	Levelized Busbar Cost (cents / kWh)
• CFB Coal / Pet coke Blend	6.9
• CFB with 10% Biomass	7.4
• CFB with 20% Biomass	8.4
• Natural Gas – Combined Cycle	9.8
• Natural Gas – Simple Cycle	11.7
• Wind + Natural Gas – Simple Cycle	11.1
• Solar + Natural Gas – Simple Cycle	20.8
• Wind	
• Solar	
• Combined Heat and Power	
• CFB 100% Biomass	
• Nuclear	
• Oxy-fuel Combustion	
• Fuel Cells	
• Hydroelectric	
• Geothermal	
• Wave Energy	
• Chemical Looping	

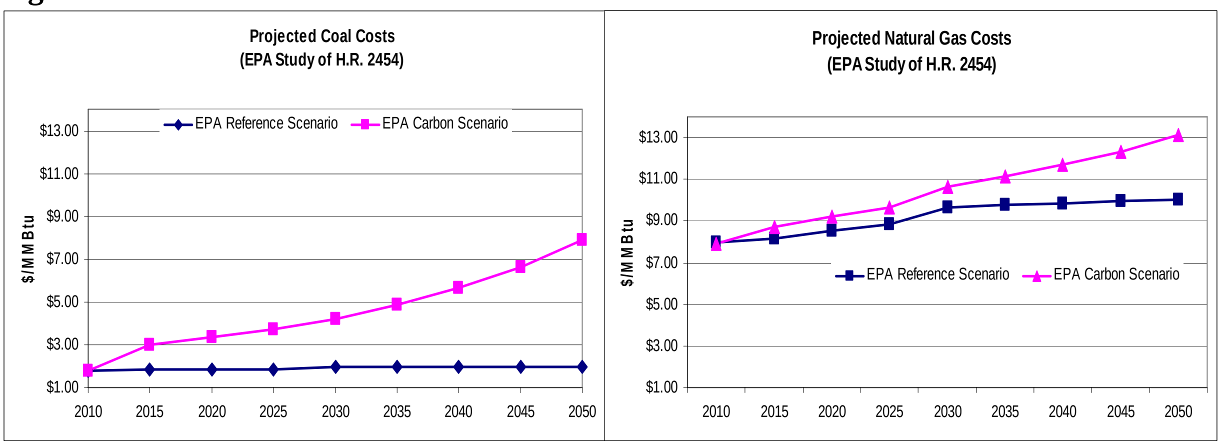
In the development of the 20-year levelized busbar cost estimates for each of the alternatives, Wolverine made several assumptions. Wolverine used 20 year projections of fuel prices under a single scenario which did not incorporate any potential risk from the regulation of carbon. While Wolverine's least cost planning considered a $42.14/ton price for carbon in the carbon tax scenario, such a scenario was not considered within the levelized busbar analysis. Staff notes that future risks such as fuel price volatility, and price risk from potential future carbon legislation should be considered within the levelized busbar cost analysis.

[60] Wolverine EGAA, Table 6.4, p. 98.

Carbon Risk

The American Clean Energy and Security Act of 2009, H.R. 2454 that would regulate CO_2 emissions was recently passed by the U.S. House of Representatives and includes a carbon cap and trade program. While that legislation is still under consideration, the U.S. Environmental Protection Agency (EPA) recently conducted a study of its potential impacts.[61] While the EPA considered several scenarios, the graphs in Figure 3 depict one scenario[62] showing a potential rise in average fuel prices from the proposed carbon cap and trade legislation, versus a reference case which assumes business as usual.

Figure 3[63]



The area between the two curves in each graph shows potential financial risk in future coal and natural gas prices due to proposed H.R. 2454 CO_2 legislation as predicted by the EPA.

In addition to increases in fossil fuel prices, carbon legislation may also lead to higher electricity prices from sources that burn fossil fuels and emit CO_2. Additional investments in carbon capture and sequestration may be evaluated to comply with such future regulation. A study released by Energy Policy Group and Christensen Associates Energy Consulting earlier this year attempted to analyze the electricity price impacts of alternative carbon emission cap and trade programs in the Midwest. While electricity prices are predicted to rise due to the proposed carbon legislation, the study states "that there are considerable uncertainties inherent in these estimates. First and foremost, we do not know with any certainty the carbon emissions reductions that will be required by either regional programs in the Midwest or by federal legislation."[64]

---

[61] EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress, 6/23/09, http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf.

[62] EPA's Scenario 2, or draft Scenario in the ADAGE model results, EPA's H.R. 2454 analysis, data annex, ADAGE model results, http://www.epa.gov/climatechange/economics/economicanalyses.html#hr2452.

[63] Coal and Natural Gas prices are U.S. average prices as projected by the EPA, EPA's H.R. 2454 analysis, data annex, ADAGE model results, http://www.epa.gov/climatechange/economics/economicanalyses.html#hr2452.

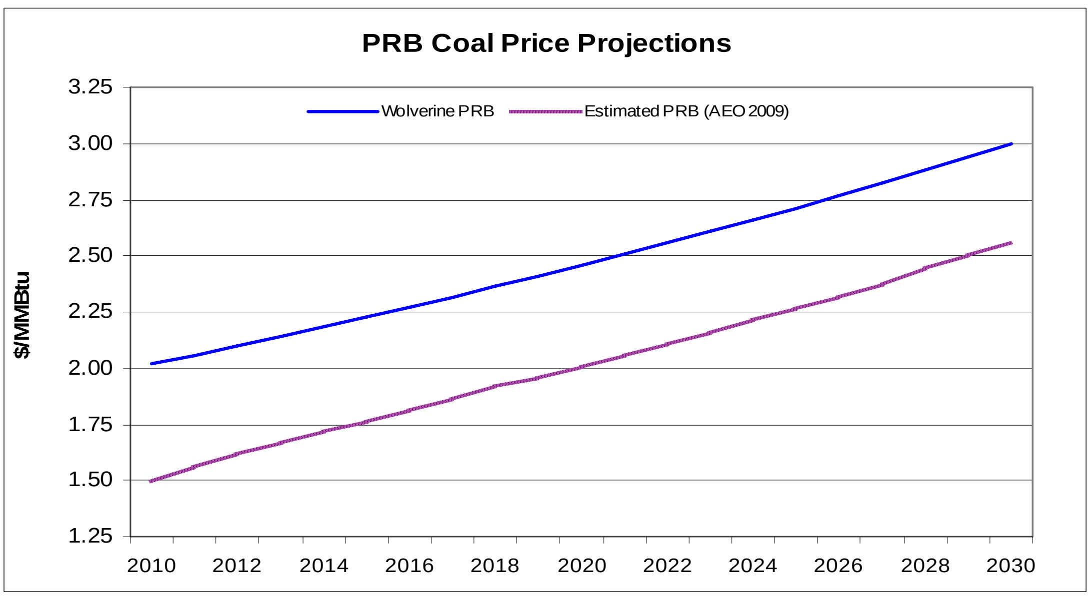
[64] Energy Policy Group LLC and Christensen Associates Energy Consulting LLC, "Analysis of the Electricity Price Impacts of Alternative Carbon Emission Cap and Trade Programs in the Midwest", http://www.euci.com/energize/8-14-09_cap-trade.pdf, p. 38.

While a great deal of uncertainty exists regarding the future of CO_2 legislation in the United States, Staff contends that the potential risks associated with the future regulation of carbon should be evaluated and considered accordingly. Wolverine's least-cost planning screening model assumed a $42.14/ton carbon tax, and a 25% increase in natural gas prices in 2015, however, Wolverine did not assume any potential impacts from carbon legislation within the 20-year levelized busbar analysis.

Fuel Price Assumptions

Wolverine's price forecast for powder river basin (PRB) coal depicted in Figure 5[65] was obtained from an analysis provided by Burns and Roe Enterprises and Energy Ventures Analysis. Also depicted in Figure 5 are estimates of delivered price projections of PRB projections based upon minemouth prices from the Energy Information Agency (EIA) Annual Energy Outlook (AEO) 2009, and transportation assumptions used in the 21st Century Energy Plan. The estimated delivered PRB projections are shown in nominal dollars.

Figure 5[66]



The common trend is that real PRB coal prices are projected to increase, however the prices in Figure 5 are in nominal dollars. While all price forecasts for commodities contain varying degrees of uncertainty and associated risk, fundamental cost drivers for PRB production support an expectation of long-run increases in the real price of PRB coal.[67]

[65] In order to accurately compare fuel forecast from various information sources, all prices were converted to nominal dollars assuming a constant 2% annual inflation rate. This rate was chosen based on the Federal Reserve Open Market Committee's most recent Long Term Personal Consumption Expenditures (PCE) outlook.
[66] Wolverine's PRB estimates were taken from a 2007 EVA fuel study submitted by Wolverine to the MPSC and were adjusted for inflation by 2% per year. The estimated PRB projection based upon the AEO 2009 utilized minemouth prices reported inTable 122 of AEO 2009, and delivery assumptions for PRB to Michigan from 21st CEP assumptions with inflation of 2% per year added. Nominal dollars.
[67] EIA, *Annual Energy Outlook 2009*, pgs 83-84

While Wolverine's projection of coal prices appears relatively conservative[68] through 2030 compared to EIA's projections, significant risk exists regarding how relative fuel prices will play out in the face of increasingly stringent environmental regulations throughout the life of the proposed plant. Staff notes that the risk of higher than expected coal prices on the operating cost of Wolverine's proposed plant is partially hedged by the plant's ability to use pet coke blends and up to 20% biomass.

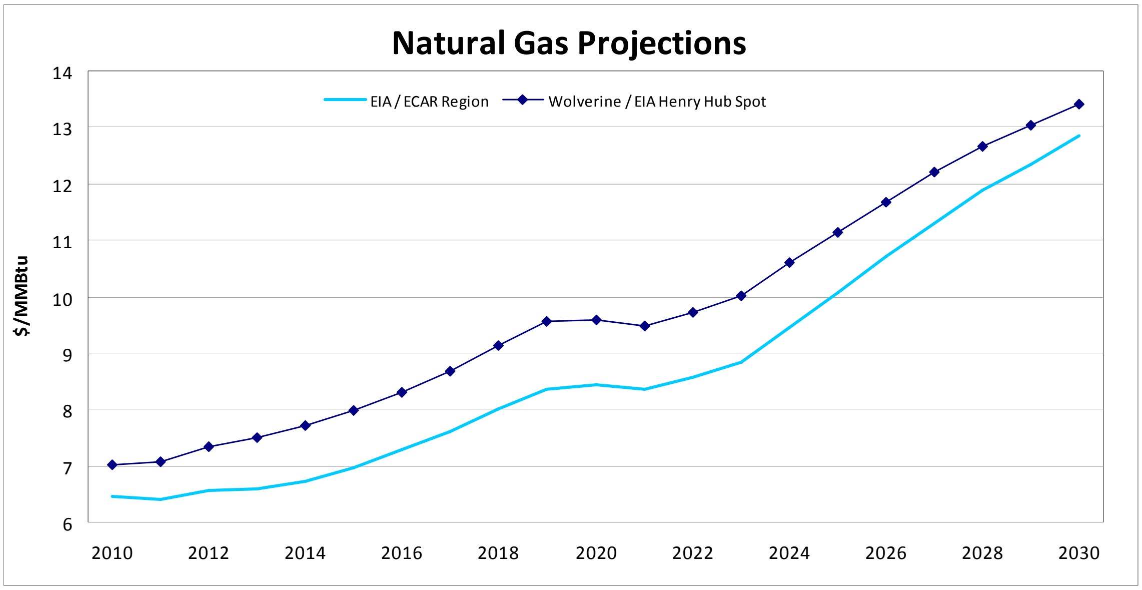
Staff notes that the EPA study predicts that the proposed CO_2 legislation would have significant measureable impacts on coal prices. Dramatic increases in fuel prices would impact the levelized cost; however, Wolverine's 20-year levelized busbar analysis did not consider any price impacts from potential CO_2 legislation. In the event that such regulation does come into existence, the price of carbon and its effect on coal commodity prices is highly speculative. However, Staff contends that consideration of such a state of the world and its affect on fuel prices is necessary in order to address the risks associated with any particular generation technology.

For natural gas price projections, Wolverine relied on the EIA's March 2009 release of the AEO.[69] Wolverine utilized projected Henry Hub spot prices for natural gas. In comments, Synapse Energy Economics contends that "it would have been more appropriate for Wolverine to have used the information on the gas prices for electric generation in the East Central Area Reliability Coordination Agreement (ECAR) region that were presented in Table 72 of the AEO. This region includes Michigan."[70]

Figure 6 shows a graphical representation of Wolverine's natural gas price assumptions and also depicts the EIA's projection of natural gas prices for the ECAR region. While Henry Hub prices are commonly used as a reference, Michigan does receive natural gas from areas other than the gulf including the Rockies and Canada. Staff notes that the EIA's natural gas projections for the ECAR region are slightly lower than EIA's projections for Henry Hub prices and would have impacted the levelized busbar analysis, had they been used.

[68] In this case, conservative refers to relatively high price levels.
[69] This projection represents Henry Hub Spot Prices from the March 2009 AEO Table 13.
[70] Comments from Synapse Energy Economics, http://efile.mpsc.state.mi.us/efile/docs/16000/0063.pdf, p. 19.

Figure 6[71]



Public comments were filed stating that there is no evidence to support claims that carbon regulation would result in any significant increase in the price for natural gas and point toward recent reports stating that new profitable access to unconventional gas sources have lead to revised downward price projections based on this new state of domestic supply.[72] The *2009 Annual Energy Outlook* (AEO) projects that domestic unconventional gas production is expected to increase by ten percent by 2030.[73] However, this report describes how access to these unconventional sources is largely a function of domestic market prices due to its relatively high cost of production. The 2009 AEO projects natural gas prices under multiple scenarios. All of them, including a scenario involving construction of a new Alaskan pipeline in service by 2022, result in long-run increases in natural gas prices driven by increasing cost of production and demand.

Staff also notes that the EPA's study on the Waxman-Markey legislation does predict an increase in natural gas prices from the proposed legislation. While recent declines in domestic natural gas prices are generally attributed to the downturn in the U.S. economy, future projections remain highly speculative in the face of changing supply conditions, technological advancements, carbon regulation and possible pipeline development.

Key Observations

[71] Data for EIA / ECAR region was taken from March 2009 AEO Table 72; Data for Wolverine / EIA Henry Hub was taken from March 2009 AEO Table 13.
[72] In Case U-15996, the Natural Resources Defense Council (NRDC) filed document #139 which is Synapse Energy Economics, Inc. response to Consumers' EGAA. A review of natural gas forecasts and cited references can be found on pgs 31-36.
[73] http://www.eia.doe.gov/oiaf/aeo/gas.html

While Wolverine's least cost planning screening analysis considered a carbon tax scenario, Wolverine's 20-year levelized busbar cost analysis does not include any potential future costs for carbon. Wolverine's 20 year fuel price forecasts for purpose of levelized cost comparison represent forecasts under a single scenario. Wolverine's analysis would have been more robust if future carbon prices had been considered in the 20-year levelized cost analysis, under multiple scenarios. Wolverine's analysis would also have been improved, had there been some inclusion of smaller quantities of multiple alternatives in their portfolio to compare with the single 600 MW Rogers City proposal.

Staff notes that energy efficiency, demand side options, and purchased power are not among the list of alternatives that was considered. While Wolverine's EGAA discusses limitations of energy efficiency and demand side options, and discusses the risks associated with purchased power, Wolverine did not consider smaller (incremental) quantities of these options in combination with any of the alternatives listed above as a portfolio of alternatives to be compared with the Rogers City alternative.

Wolverine's EGAA does not present an adequate analysis of the costs and benefits of reliance on short-term power supply options to mitigate long-term planning risk. The risks associated with a long-term central station investment based on unusually speculative cost levels and shifting regulation paradigms appear significant enough to warrant a thorough review of short-term resource options. Short-term resource options include load management, short lead-time renewable options, natural gas combustion turbines, and purchased power. The future risks of long-term investments should be weighed against the potential risks of utilizing viable short-term options while delaying a longer-term investment.

Wolverine Power Cooperative - Alternatives Analysis

Proposed Generation

Wolverine consulted with Burns and Roe Enterprises to perform an evaluation of coal-fired technologies including supercritical pulverized coal, ultra-supercritical pulverized coal, sub-critical circulating fluidized bed, supercritical circulating fluidized bed, and integrated gasification combined cycle. Burns and Roe then performed an evaluation of Rogers City site-specific alternatives including pulverized coal and circulating fluidized bed technology options. The complete report from Burns and Roe is included as Appendix A-2 of Wolverine's EGAA.

Wolverine's Clean Energy Venture proposal has two components:

- A 600 MW (2 x 300 MW) CFB plant planned to operate on a blend of PRB coal and petroleum coke as a baseload plant.
- A proposed wind farm that is still under investigation.

The subcritical CFB plant proposed for Rogers City would be located on property that is mined for limestone, and would have an estimated heat rate of 9105 Btu/kWh operating on a 30/70 blend of petroleum coke and PRB coal.[74] The plant has also been designed to accommodate up to 20% biomass, and has been designed with sufficient space to allow for future implementation of carbon capture and sequestration. The proposed site, within the confines of an active limestone quarry just outside of Rogers City provides the following advantages[75]:

- The setting within the quarry would allow the plant to be built with minimal aesthetic impact.
- Only a modest expansion of the harbor facilities would be necessary for unloading of fuels
- Potential exists for shipping productivity improvements, as Wolverine is investigating having ships that currently come in empty to ship out limestone, instead come in with solid fuels for the power plant and leave with limestone.
- The quarry has a continuous dewatering operation which would provide cooling water to the power plant.

CFB technology has been used broadly in the industrial industry and use in the utility industry of larger-sized subcritical CFB boilers is growing. Wolverine's EGAA[76] lists CFB plants in the United States that have recently been built or are under construction. Wolverine's EGAA contends that "design enhancements, improved fuel management, and operating techniques have allowed CFB plants to have capacity factors equal to those of PC plants,"[77] which is typically greater than 85%.

Wolverine states that CFB technology is best suited for the Rogers City project for the following reasons[78]:

1. Mature technology and commercially proven for boiler sizes up to 300 MW;
2. Greater fuel flexibility than PC;
3. High ash/sulfur fuel easily burned (lignite bituminous coal, pet coke, waste, biomass, as compared to PC;
4. Low temperature combustion minimizes NO_x and SO_x formation;
5. SO_x control in furnace requires less back-end emissions cleanup than PC;
6. CFB design results in the lowest levelized cost of electricity;
7. Ability to handle a wide variety of fuels, including high percentages of pet coke, with relatively little extra capital cost;
8. Plant can be economically designed to accept biomass fuels, which are carbon-neutral and come from sustainable sources that can be developed within close proximity;
9. Ability to accept a wide range of fuels provides Wolverine with negotiating leverage for fuel procurement and a hedge against fuel price volatility;
10. Availability of limestone on site best complements the CFB technology; and

[74] Wolverine EGAA Appendix A-2, p. A2-81.
[75] Wolverine EGAA Appendix A-2, p. A2-7.
[76] Wolverine EGAA, Table 6.3, p.81.
[77] Wolverine EGAA, p. 82.
[78] Wolverine EGAA, p. 77.

11. Ability to use a dry flue gas desulfurization (FGD) system instead of a wet FGD system makes it economically feasible to design this plant as a zero liquid discharge (ZLD) facility.

Wolverine's EGAA also discusses disadvantages associated with subcritical CFB technology including:
1. Heat losses through cyclone separator and sorbent addition degrades slightly efficiency/heat rate.
2. Of the five (coal-fired) options evaluated (in Wolverine's EGAA Appendix A-2), CFB has the largest volume of solid waste for disposal.
3. Disposal of alkaline/toxic/leachable bottoms waste, FGD/baghouse waste.

Wolverine's EGAA[79] lists the following 20-year levelized busbar costs for the proposed CFB technology with varying fuel blends that were evaluated:

Technology Evaluated	20-Year Levelized Busbar Cost
CFB Pet Coke/PRB Coal	6.9 cents / kWh
CFB Pet Coke/PRB Coal/10% Biomass	7.4 cents / kWh
CFB Pet Coke/PRB Coal/20% Biomass	8.4 cents / kWh

The 20-year levelized busbar costs reported by Wolverine do not include any future costs for carbon. Wolverine's busbar analysis indicates that the CFB fueled by petroleum coke and PRB coal is the least cost option over the 20-year period. Wolverine's levelized cost for the CFB plan includes the capital cost assumption of $2200/kW that has been criticized as being too low in the public comments. Staff notes that Wolverine's Technology Selection Study by Burns and Roe Enterprises included as Appendix A-2 to the EGAA lists a capital cost of $2484/kW[80] for CFB technology in 2006 dollars. Using a 3% inflation rate, the Burns and Roe CFB capital cost would be $3241/kW in 2015 dollars.

While this significant difference in capital cost assumptions between Burns and Roe and Wolverine ($3241/kW versus $2200/kW) would have a measurable impact on the levelized cost analysis, Staff also acknowledges that Burns and Roe's estimate for a pulverized coal unit at Rogers City at $2685/kW in 2006 dollars was higher than their estimate for the CFB alternative at $2484/kW in 2006 dollars, suggesting that CFB is the choice coal technology for Rogers City as evaluated by Burns and Roe. Although Wolverine's lower estimate of the capital costs for the CFB alternative have an influence on the levelized costs, it is unclear how much higher of a capital cost assumption for the CFB unit would have been necessary to lead to a different rank order of the alternatives that were evaluated. It is clear that the levelized busbar analysis would have been more robust if Wolverine had included a sensitivity with higher capital costs for the proposed CFB unit.

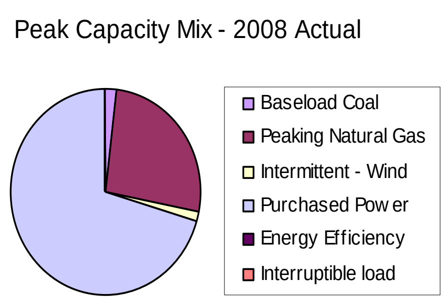
Public comments also highlighted uncertainty surrounding future carbon legislation and its associated costs as a significant issue that should be considered in the evaluation. Wolverine plans for future risks associated with carbon in two ways. First, Wolverine's

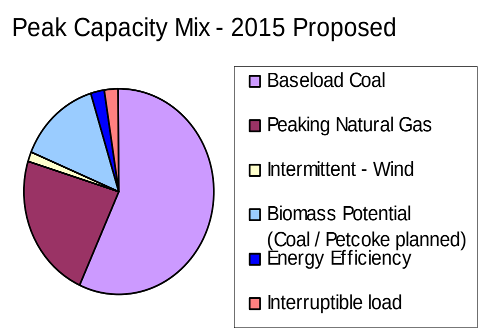
[79] Wolverine EGAA, Figure 6.6, p. 99.
[80] Wolverine EGAA Appendix A-2, p. A2-95.

design has space set aside for the future implementation of carbon capture and sequestration, although Wolverine did not attempt to quantify the costs associated with carbon capture and sequestration, nor were any financial assumptions for carbon included in the levelized busbar analysis. Second, Wolverine states that "use of carbon neutral biomass at Wolverine will reduce the CO_2 footprint linearly. Wolverine plan can use 20% of biomass without any special provisions. This will reduce its CO_2 emissions below those from SC and ultra SC PC."[81]

Public comments filed also discussed the transmission upgrades necessary to support the proposed Rogers City site. Comments filed on behalf of the Sierra Club and the Environmental Law and Policy Center state that the transmission benefits of Wolverine's proposed plant are overstated within its EGAA, and that if the transmission upgrades are needed to support the proposed plant, then "the cost of building that line should be considered part of the cost of the plant."[82] The details of the proposed transmission upgrades necessary to support the proposed plant at the Rogers City site are still under evaluation at the Midwest ISO and the cost estimates will be supplied by the transmission company, ITC Holdings. Staff contends that the inclusion of estimated transmission upgrades necessary to support the proposed facility in an alternatives analysis is warranted.

The addition of the proposed Rogers City CFB plant would alter Wolverine's generation portfolio substantially. The following figure shows Wolverine's actual peak capacity mix for 2008, and their planned peak capacity mix for 2015 with the addition of the proposed Rogers City facility[83].





Alternative Coal Technologies

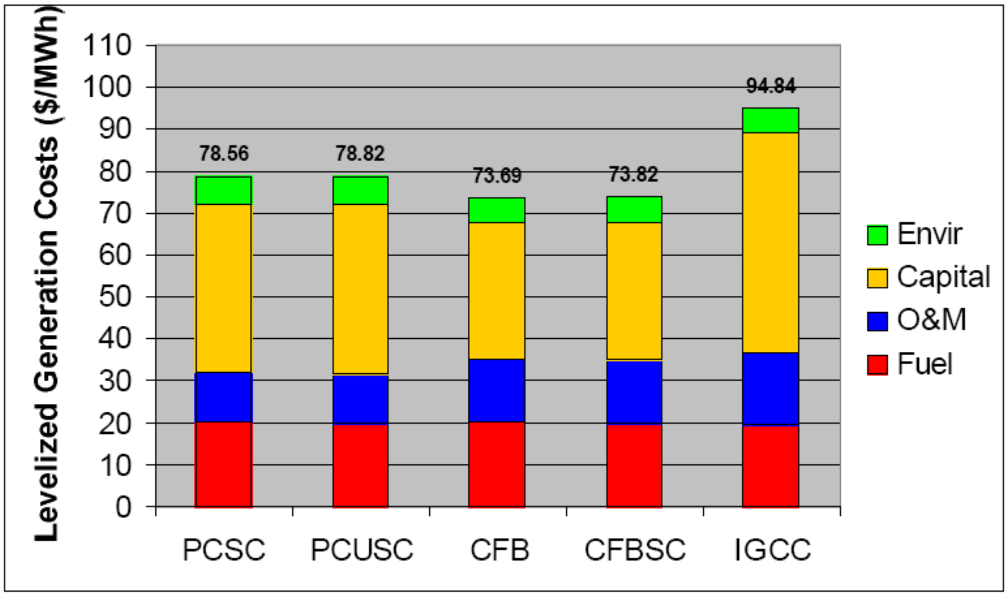
Wolverine consulted with Burns and Roe Enterprises to perform a technology assessment study of coal-fired technologies to meet Wolverine's resource needs. According to Burns and Roe, there are five technologies commercially available for power generation from solid fuels:[84]

---

81 Wolverine EGAA Appendix A-5, p. A5-5.
82 Comments filed on behalf of the Sierra Club and the ELPC, http://efile.mpsc.state.mi.us/efile/docs/16000/0112.pdf, p. 8.
83 According to Wolverine's EGAA, wind capacity is credited with 20% of nameplate capacity on-peak per MIDWEST ISO's Resource Adequacy Business Practice Manual dated 5/26/09.
84 Wolverine EGAA Appendix A-2, p. A2-9.

- Pulverized coal, supercritical steam cycle (PCSC)
- Pulverized coal, ultra-supercritical steam cycle (PCUSC)
- Circulating fluid bed, subcritical steam cycle (CFB)
- Circulating fluid bed, supercritical steam cycle (CFBSC)
- Integrated Gasification Combined Cycle (IGCC)

In the evaluation for Wolverine, Burns and Roe completed a screening analysis for each of those five technologies. Based upon a 1200 MW unit of each commercially available technology type, the results for the economic evaluation are shown:[85]

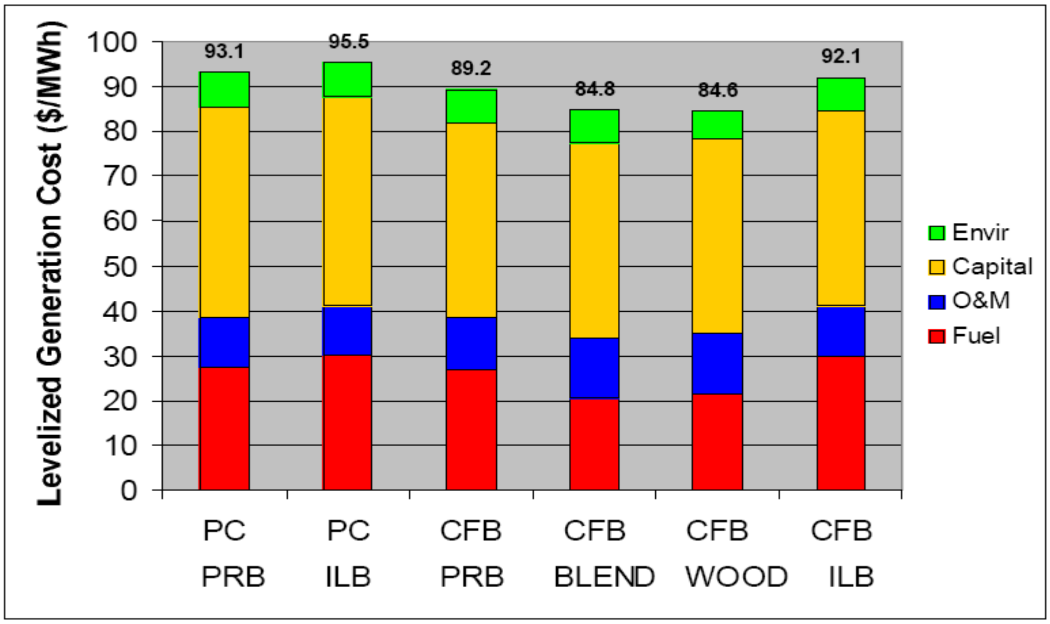


Following the initial screening analysis, Burns and Roe chose the top two ranked alternatives to perform a site-specific analysis for Wolverine. The ultra-supercritical pulverized coal, supercritical CFB, and the IGCC alternatives were screened out from the initial analysis reportedly as representing an unacceptable risk for a small electric cooperative like Wolverine for several reasons.[86]

Ultra-supercritical pulverized coal has the best proven thermal efficiency and heat rate, however, there are very few units in operation, none of which are in the United States, and it provides less fuel flexibility than a CFB or IGCC alternative. Supercritical CFB technology does not have any proven operating experience, as the first one of its kind is currently being built in Poland. The IGCC technology reportedly has the potential to be the alternative with the best thermal performance, the lowest emission capability during steady-state operation, and lends itself to ease in implementation of carbon capture and sequestration. However, the IGCC alternative was eliminated from the subsequent site-specific evaluation because it was the most expensive option, and IGCC is a new and developing technology with limited operating experience.

[85] Wolverine EGAA, Appendix A-2, p. A2-51.
[86] Wolverine EGAA Appendix A-2, p. A2-52 – A2-55.

Burns and Roe then completed a site-specific evaluation for the two alternatives that scored the highest in the screening process, which are the subcritical CFB and the supercritical PC alternatives at 600 MW capacity size. The site-specific economic analysis evaluated various fuel blends that included Illinois Basin coal (ILB), Powder River Basin coal (PRB), petroleum coke, and wood biomass. Exhibit 58[87] of the Burns and Row assessment includes the detailed summary of the site specific economic analysis for each of the fuel blends. A graphical representation of the site-specific economic results is shown:[88]



*CFB Blend in the above chart represents a blend of petroleum coke and PRB coal, while CFB Wood in the above chart represents a blend of petroleum coke, PRB coal, and wood.

Acknowledging that the site-specific economic analysis results are based upon key input assumptions, Burns and Row also completed the following sensitivity analyses:[89]

- Sensitivity to pet coke delivered price
- Sensitivity to PRB delivered price
- Sensitivity to capital cost
- Sensitivity to activated carbon cost
- Sensitivity to CO_2 emissions costs

The results from the sensitivity analyses from Burns and Row are included in Appendix A-2 of Wolverine's EGAA. Based upon the results, Wolverine chose to propose the 2 x 300 MW subcritical CFB alternative for Rogers City. As part of their alternatives analysis Wolverine submitted the following 20-year levelized busbar costs for solid fuel technologies:

87 Wolverine EGAA, Appendix A-2, p. A2-95.
88 Wolverine EGAA, Appendix A-2, p. A2-94.
89 Wolverine EGAA, Appendix A-2, p. A2-95.

Technology Evaluated	20-Year Levelized Busbar Cost[90]
CFB Pet Coke/PRB Coal	6.9 cents / kWh
CFB Pet Coke/PRB Coal/10% Biomass	7.4 cents / kWh
PC Subcritical PRB	7.5 cents / kWh
PC Supercritical PRB	7.8 cents / kWh
CFB Pet Coke/PRB Coal/20% Biomass	8.4 cents / kWh

The 20-year levelized busbar costs reported by Wolverine do not include any future costs for carbon. Wolverine plans to operate the CFB unit on a blend of petroleum coke and PRB coal, but the unit has been designed to accommodate coal from the Illinois basin, as well as up to 20% of biomass. Based upon the analysis from Burns and Row and Wolverine, the CFB alternative is the least cost alternative and also provides fuel flexibility, including future flexibility towards reducing carbon emissions and adding in a renewable fuel.

Staff notes that the levelized busbar analysis results are dependant upon the financial assumptions for capital and fuel prices. Staff acknowledges that the coal alternative evaluated by Wolverine have lower busbar costs than many of the other alternatives, however, the ranking of coal technologies versus other alternatives may change in the future, should legislation regulating CO_2 be enacted.

Energy Efficiency and Load Management

Energy Efficiency

Wolverine included the following assumptions regarding energy efficiency within their load forecasts:

Timeframe	Energy Efficiency Assumption	Basis for Assumption
2009	0.3% Energy savings	2008 PA 295[91] requirements
2010	0.5% Energy savings	2008 PA 295 requirements
2011	0.75% Energy savings	2008 PA 295 requirements
2012 – 2015	1% Energy savings	2008 PA 295 requirements
2016 - 2021	0.2% Energy savings per year	EPRI report[92]

Wolverine adjusted their base case forecasts to reflect expectations of its member cooperatives meeting the targets set forth by 2008 PA 295 through 2015. For 2016 through 2021, Wolverine reduced the expected amount of energy efficiency to 0.2% per year to reflect "the amount indicated as the Realistic Achievable Potential (8.2% by 2030) by the Electric Power Research Institute (EPRI) energy efficiency study entitled 'Potential U.S.

[90] Wolverine EGAA, p. 99.
[91] 2008 PA 295, http://www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf.
[92] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010 – 2030). Electric Power Research Institute (EPRI), http://mydocs.epri.com/docs/public/000000000001018750.pdf.

Energy Efficiency Savings - 2008 to 2030'."[93] Wolverine's assumed reductions to peak demand for their member cooperatives from the energy efficiency assumptions are as follows:

Year	Wolverine's Assumed Reductions to Peak Demand from Energy Efficiency[94]	Peak Reduction / Forecasted Peak
2009	1 MW	0.15%
2015	22 MW	3.10%
2021	26 MW	3.19%

Several public comments contend that Wolverine's assumptions for energy efficiency are too conservative and that there are several policy initiatives underway that place EPRI's realistic achievable potential estimates for energy efficiency in question. The Michigan Climate Action Council (MCAC) released a report in 2009 that included recommendations to expand the current energy optimization requirements that were enacted through 2008 PA 295. The MCAC recommends "annual incremental electricity savings in 2016 and each year thereafter through 2025 equivalent to 2.0% of total annual retail electricity sales in MWh in the preceding year."[95]

Staff requested Wolverine to describe potential changes to their overall supply plan, should the MCAC policy recommendation of 2% per year energy optimization savings come to fruition. Wolverine states, "An increased energy optimization target would lower Wolverine's future needs; however, the reductions afforded by these increased energy optimization targets would not replace Wolverine's need for its proposed Rogers City project. … An increased energy optimization target of 2% per year beyond 2015 would reduce Wolverine's 2021 base case peak by less than 50 MW."[96] The impact to peak demand for their member cooperatives of implementing the MCAC energy efficiency targets to Wolverine's resource plan is shown:

Year	Wolverine's Assumed Reductions to Peak Demand from Energy Efficiency[97]	Wolverine's Projected Reductions to Peak Demand from EE at 2% beyond 2015
2009	1 MW	1 MW
2015	22 MW	22 MW
2021	26 MW	75 MW

Load Management

[93] Wolverine EGAA, p. 25.
[94] Wolverine Response to Staff Questions, 6/23/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf, p.8.
[95] Michigan Climate Action Plan, MCAC Final Report - March 2009, Appendix F – Energy Supply Policy Recommendations, http://www.miclimatechange.us/ewebeditpro/items/O46F21198.pdf, p. F-11.
[96] Wolverine Response to Staff Questions, 7/9/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0090.pdf, p. 1.
[97] Wolverine Response to Staff Questions, 6/23/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf, p.8.

Wolverine set into place a load management program dating back to 1992 in efforts of decreasing winter peak consumption. The program with specific focus on direct control of water heaters, electric heating systems with alternative energy back-up systems, and oil pumping load, worked well for the 2 hour length of the peak. Using this program, 20MW of winter load was eliminated. By 2001 Wolverine became a summer peaking utility due to conversion of seasonal residences turning into primary residences, C&I customer increase, and increase usage of air conditioning units. Wolverine plans anticipates further implementation of their integrated load management incentive rates in efforts of reducing future peaking capacity.

Three out of the four Wolverine distribution cooperatives have installed, or are in the process of installing Advanced Metering Infrastructure (AMI) Systems. Within the current resource plan in the EGAA, Wolverine "expects to continue its load management incentive rates and anticipates that once AMI integration issues are resolved, this integrated load management system will help reduce future peaking capacity investments. Wolverine estimates that up to 20 MW of peak load could be controlled with a revamped load management system."[98]

Wolverine's assumption of 20 MW of load management is 2.8% of Wolverine estimated peak demand of 710 MW in 2015.[99] Combining Wolverine's 20 MW of load management with the expected peak reduction from energy efficiency of 22 MW in 2015, Wolverine is assuming a total of 5.9% peak load reduction from energy efficiency and load management. Should the MCAC goals of 2% reductions per year come to fruition, Wolverine's combined reduction to peak from energy efficiency and load management would be 11.8% in 2021.

According to EPRI's assessment on energy efficiency and demand response, 14.0% of summer peak demand is a Realistic Achievable Potential for 2030, while 19.5% of summer peak demand is a Maximum Achievable Potential for 2030.[100] Considering the MCAC goal of 2% incremental energy efficiency per year starting in 2015, Wolverine's combined estimated peak reduction from energy efficiency and load management at 11.8% of peak demand in 2021 may fall into line with EPRI's Realistic Achievable Potential of 14.0% by 2030.

According to the 21st CEP, the effective use of demand response programs can be cost effective and in the public interest. Staff asserts that energy efficiency and load management options should continue to be evaluated and implemented whenever viable.

Renewable Energy

To satisfy the requirements of 2008 PA 295, Wolverine must supply 10% of its energy from renewable resources by 2015. Currently Wolverine states that it "has a long-term agreement with John Deere Wind Energy for 100 percent of the output of the Harvest Wind

[98] Wolverine EGAA, p. 39.
[99] Wolverine Response to Staff Questions, 6/23/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0023.pdf, p.8.
[100] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010 – 2030). Electric Power Research Institute (EPRI), pg. 5-2.

Farm in Michigan's Thumb yielding approximately 138,000 MWh each year of additional renewable energy based on a 30 percent capacity factor."[101]

Each renewable technology was evaluated by Wolverine in terms of cost, reliability, availability, efficiency, technical feasibility, emissions and risks as discussed in this report. Wolverine's EGAA[102] lists the following levelized busbar costs that it developed for renewable resources:

Technology Evaluated	20-Year Levelized Busbar Cost[103]
Wind Only (Note 1*)	8.8 cents / kWh
Wind & Gas Turbine	11.1 cents / kWh
Fuel Cell	16.8 cents / kWh
Solar & Gas Turbine	20.8 cents / kWh

*Note 1 regarding wind states, "Wind (only) does not match the capacity and energy supplied by other alternatives in Figure 6.6 (p. 99 of Wolverine EGAA). It must be combined with another technology (natural gas simple-cycle or combustion turbines) to achieve performance (in terms of capacity and energy) comparable to the other technologies included in Figure 6.6. The same is also true for solar (only)."[104] Although costs were not explicitly provided, Wolverine's EGAA also considered hydroelectric, geothermal, CFB with 100% biomass, combined heat and power, and several other alternatives as well.

Wind

Wolverine currently has a long-term agreement with John Deere Wind Energy for 100 percent of the output (52.8 MW) of the Harvest Wind Farm in Michigan's thumb. Wolverine states that "the capacity factor for this wind farm was about 25% in the first year."[105] Wolverine has also installed a met tower at Adam's Point, very near the proposed Rogers City proposed CFB plant site. Wolverine plans to evaluate the data captured by the met tower to potentially expand the use of wind in their portfolio in the future.

Wolverine discussed additional on-shore wind resources in their least-cost planning analysis and provided cost estimates in their levelized busbar cost analysis. Within the least-cost planning screening analysis, Wolverine states that intermittent generation such as wind and solar do not fit well within the confines of traditional planning models. "The reason for this is simple: the low variable cost of operation (i.e., very low-cost fuel) suggests these units should be first to run; however, these assets are not dispatchable, and output levels are often dictated by weather, not economic conditions. To be clear, this does not mean that intermittent resources are inherently negative. These plants can displace

[101] Wolverine Response to Staff Questions, 7/9/09, p. 2.
[102] Wolverine EGAA, Figure 6.6, p. 99.
[103] Wolverine EGAA, p. 99.
[104] Wolverine EGAA, p.99.
[105] Wolverine EGAA Appendix A-1, p. A1-11.

older, less efficient plants that lack modern environmental controls, but they do have operational limitations that must be considered in the planning construct."[106]

Wolverine also provided levelized busbar costs for wind, and wind plus supplemental natural gas-fired generation within the levelized busbar analysis. The levelized cost for wind provided by Wolverine was 8.8 cents per kWh[107], which is higher than the levelized costs provided by Wolverine for CFB with a blend of pet coke and coal, CFB with a blend of pet coke and coal and 10% or 20% biomass, pulverized coal subcritical and supercritical, and nuclear alternatives.

In addition to the higher levelized costs for wind, Wolverine states that "Wind (only) does not match the capacity and energy supplied by other alternatives in Figure 6.6 (p.99 of Wolverine EGAA). It must be combined with another technology (natural gas simple-cycle or combustion turbines) to achieve performance (in terms of capacity and energy) comparable to the other technologies included in Figure 6.6."[108] Staff notes that Midwest ISO currently credits new wind projects with 20% on-peak capacity to meet the reserve margin requirements set forth in the Module E portion of the Midwest ISO tariff. A new 600 MW wind farm would be credited with only 120 MW of on-peak capacity to meet Midwest ISO's reserve requirements for Wolverine member-owners. Wolverine provided a levelized busbar cost for wind plus gas turbine capacity of 11.1 cents per kWh.

Staff disagrees with the assertions made by Wolverine to not include wind capacity which the Company lists as "technically feasible … at a capacity of 600MW"[109] beyond a supplemental recourse as an alternative for evaluation. Staff does acknowledge that Midwest ISO tariff requirements for capacity and reserves must continue to be met. Staff maintains that the best generation systems will use a variety of resources[110] and also that wind contributes measureable benefits to base load.

Also, Wolverine lists the intermittent and unpredictable nature of wind as a generation resource. Staff, although agreeing in part, maintains that there are mitigating factors which will reduce the impacts of the discontinuous nature of wind. These factors include geographic diversity of wind generation and the improving predictability (forecasting) of wind that is available to be incorporated into the operating practices of generators.[111]

Wolverine acknowledges that "most places suitable for building a wind farm [in Michigan] are off the shore of Lake Superior, Lake Michigan, Lake Huron, and Lake Erie." [112] Although Wolverine acknowledges the potential of offshore wind, Wolverine's EGAA fails to include offshore wind capacity in its portfolio. Staff asserts that as additional information is gathered regarding off-shore wind development (i.e., collection of data)

---

[106] Wolverine EGAA, p. 42.
[107] Wolverine EGAA, p. 99.
[108] Wolverine EGAA, p. 99.
[109] Wolverine Power Cooperative EGAA, http://efile.mpsc.state.mi.us/efile/docs/16000/0001.pdf, p. 96
[110] Michigan Public Service Commission, Michigan's 21st Century Electric Energy Plan (Lansing, 2007), 25.
[111] U.S. Department of Energy, 2008 Wind Technologies Market Report (Lawrence Berkeley National Laboratory, 2009), 48-49.
[112] Wolverine EGAA Appendix A-1, p. A1-12.

advancements in research and technologies will likely enable such development in the Great Lakes.

In addition, policy decisions will be necessary in order to effectively promote off-shore wind development in the Great Lakes. At this time, the Michigan Great Lakes Wind Council[113] created by Executive Order 2009-1, is actively examining these issues. The Council serves as an advisory body within the Michigan Department of Energy, Labor & Economic Growth to examine issues and make recommendations related to offshore wind development in Michigan. The council consists of key state agency representatives and stakeholders appointed by Governor Jennifer M. Granholm.

The Council is charged with the following tasks: Identify criteria that can be used to review applications for offshore wind development, and; Identify criteria for identifying and mapping areas that should be categorically excluded from offshore wind development as well as those areas that are most favorable to such development, and provide these criteria in a report to the governor by September 1, 2009.

Solar

Wolverine considered solar alternatives within their EGAA, however, Wolverine states that "even with thermal energy storage, a very costly and pre-commercial technology, a solar power plant would not be able to provide undisrupted power like coal and other baseload power plants, capable of meeting electricity demands at all times."[114] Wolverine did provide a levelized busbar cost of 20.8 cents per kWh for solar power combined with supplemental natural gas-fired generation.

Solar photovoltaic (PV) should continue to be evaluated so that when viable, become part of Wolverine's energy supply portfolio and it is recommended that Wolverine consider the development of a solar PV pilot program. During the early years of this planning period, a combination of small installations should be considered. Both Consumers Energy and Detroit Edison have Commission-approved solar PV pilot programs. The effectiveness of these programs will be evaluated on an on-going basis. Early indications show a high level of customer interest. This type of program could not replace a baseload plant; however, since solar PV is likely to be generated when additional power is needed; it is an essential and logical addition to a diverse supply portfolio.

The cost of solar PV has traditionally been higher than other conventional, baseload sources of electric generation. Wolverine discusses solar in its EGAA and explains that it is cost prohibitive compared to the baseload plant they propose. Research and development to lower the cost of solar PV is ongoing and has the potential to significantly impact solar PV costs. The U.S. Department of Energy Solar Energy Technologies Program PV

[113] Michigan Great Lakes Wind Council web site; http://www.michiganglowcouncil.org/index.html
[114] Wolverine EGAA Appendix A-1, p. A1-18.

subprogram's goal is for PV technology to achieve grid parity by 2015. Achieving this goal will lead to rapid and significant growth of solar electricity in the United States[115].

Staff recommends that Wolverine evaluate the solar PV pilot programs developed by Consumers Energy and Detroit with the intent to incorporate the best elements of those pilots into a reasonable pilot program for Wolverine and the member cooperatives they serve. Also, Staff recommends that Wolverine continue to assess how more solar energy could be added to its supply portfolio as advancements in solar technology become commercially available.

Staff recommends that Wolverine monitor the ongoing investigation titled "Investigation to Assess Wisconsin's Potential for the Development of Utility Investments in Solar Energy Resources to Cost-Effectively Contribute to Wisconsin's Electric Supply" at the Wisconsin Public Service Commission in docket 5-EI-147.[116] Additionally, Staff recommends that solar energy demand side management technologies (solar hot water, solar daylighting, solar space conditioning techniques) be considered as options for Energy Optimization planning.

Biomass

Wolverine has designed their proposed generation to have the ability to use up to 20% of biomass, and states that "co-firing of biomass in CFB boilers has been fully commercialized."[117] Wolverine provided the following 20-year levelized busbar costs for biomass options:

Technology Evaluated	20-Year Levelized Busbar Cost[118]
CFB (pet coke / PRB blend)*	6.9 cents / kWh
CFB (pet coke / PRB blend / 10% Biomass)	7.4 cents / kWh
CFB (pet coke / PRB blend / 20% Biomass)	8.4 cents / kWh
CFB (100% Biomass)	Not calculated

*provided for reference

The 20-year levelized busbar costs reported by Wolverine do not include any future costs for carbon. While fuel blends of 10% and 20% biomass produce higher levelized busbar costs than the planned blend of petroleum coke and PRB coal, the potential use of the biomass blend provides Wolverine with an option to reduce CO_2 emissions. Wolverine states that the "use of carbon neutral biomass at Wolverine will reduce the CO_2 footprint linearly. Wolverine [proposed Rogers City] plant can use 20% of biomass without any special provisions."[119] The potential for blending biomass fuel also provides Wolverine

115 http://www1.eere.energy.gov/solar/photovoltaics_program.html

116 A draft report is expected to be released in September 2009 and a final report is scheduled to be drafted in December 2009.
117 Wolverine EGAA, Appendix A-1, p. A1-5.
118 Wolverine EGAA, p. 99.
119 Wolverine EGAA, Appendix A-5, p. A5-5.

with an option to meet a higher renewable portfolio standard in the future. Wolverine states that "operating the Rogers City project using 20 percent biomass (on a fuel heat content basis) results in the production of approximately 995,000 MWh per year of renewable energy. At the 20 percent biomass level, and considering Wolverine's 2021 Base Case forecast, Wolverine achieves a 22 percent renewable energy portfolio for its member-owners. … The combination of the biomass component with the wind energy [from the long-term contract with John Deere Harvest Wind Farm] increases Wolverine's members' renewable energy portfolio level to 25 percent."[120]

Wolverine performed due diligence regarding the investigation of biomass co-firing by providing an unbiased biomass sustainability and life cycle analysis report from Michigan Technological University in Appendix A-3. The report concludes that a 20% wood co-firing scenario would be feasible within a 75 mile radius although Wolverine does not commit to a specific co-firing percentage.

The CO_2 benefit and economics of the transportation and lower energy content of the wood biomass compared to coal resources will still need to be carefully analyzed as these factors may negate some of the co-firing benefit. The wood residual used for the co-firing may have a higher value as forest product for non-energy related industries, therefore costing more as a co-fired fuel. It is suggested that Wolverine further investigate the opportunities to fully utilize biomass for combined heat and power (CHP) to fully exploit the potential of stored energy in the biomass fuel (see CHP section of this report).

In addition to the above mentioned research, Michigan Technological University is currently performing energy crop trials with a variety of plant and tree species (appendix A-6). The intent of this research is to study the use of dedicated crops for fuel and biological carbon sequestration. The use of quick growing fuel crops close to the plant provides an opportunity for Wolverine to benefit from reduced biomass fuel cost and negate some of the ancillary carbon dioxide emissions associated with transportation of the fuel.

Biomass has the potential to be incorporated into Wolverine's portfolio through co-firing in their proposed Rogers City facility. Staff notes that Wolverine did not evaluate the potential to install several smaller biomass facilities spread out within their territory. Smaller facilities could potentially be coupled with additional energy efficiency, load management and other renewable resources in order to lower emissions and traditional fossil fuel resource needs.

Biogas Energy

While Wolverine's EGAA considered solid biomass co-firing options, Wolverine did not consider biogas alternatives. The two main types of biogas alternatives that are typically considered are landfill gas, and anaerobic digesters.

[120] Wolverine Response to Staff Questions, 7/9/09, http://efile.mpsc.state.mi.us/efile/docs/16000/0090.pdf, p.3.

Based on the Michigan Climate Action Council Final Report; the 2025 landfill gas (LFG) potential for Michigan is 20.6 MW in addition to current LFG generation.[121] This is a conservative estimate that does not take into account advances in generation technologies or learning curve price reductions. A 2008 Department of Environmental Quality landfill map identifies 81 type II and type III landfills in throughout Michigan.[122]

Michigan's large agricultural base can provide opportunities for manure based anaerobic bio-digestion from livestock waste (i.e., wastes from hogs, cattle, turkeys, chickens, etc.). An EPA Agstar report states that electricity production from cattle manure fed anaerobic bio-digestion has the potential to produce 9.8 MW at 10% market penetration.123 Based on the most recently available data from the U.S. Department of Agriculture, the potential of manure based generation in Michigan is roughly 100MW with full penetration. Staff acknowledges that there is a limit to the potential for biogas energy within Wolverine's territory.

Hydroelectric Dams and Pumped Storage

Wolverine reports that hydroelectric power "is a widely used and efficient form of energy that generates approximately one fifth of the world's electricity."[124] Although Wolverine acknowledges that hydroelectric power is technically feasible, commercially available, and widely used, Wolverine also states that "in many places the most cost effective sites for hydroelectric power have already been exploited. The lack of new sites, environmental restrictions, and increasing costs are major obstacles that stand in the way for another hydroelectric plant in Michigan."[125]

While it is true that the legal and societal obstacles facing new dam construction are prohibitive, there are ample opportunities to take advantage of existing impoundment sites in Michigan. Michigan has over 2000 dams, with approximately 100 currently producing power. Not all of these dams are capable of electric power production, but approximately 109 of these dams are retired hydroelectric or mechanical water power dams, with significant production capacity. Power produced at these dams could be a reliable source of generation in Michigan.

Development of these resources will take serious commitment, both financial and otherwise. Environmental and recreation impacts would have to be balanced with the benefits of an expanded renewable energy portfolio and a decrease in greenhouse gas emissions. Opportunities exist for stakeholder cooperation that could lead to both increased power production and increased environmental protection and river restoration.

---

[121] Michigan Climate Action Council Report, http://www.miclimatechange.us/ewebeditpro/items/O46F21226.pdf, p. J-116
[122] MDEQ Landfill Map, http://www.michigan.gov/documents/deq/deq-whmd-swp-Landfill-map_247566_7.pdf

[123] http://www.epa.gov/agstar/pdf/biogas%20recovery%20systems_screenres.pdf

[124] Wolverine EGAA Appendix A-1, p. A1-18.
[125] Wolverine EGAA Appendix A-1, p. A1-19.

Adjustments to State and Federal regulation may be needed to ease the development of these hydroelectric resources.

Geothermal

Wolverine states that a geothermal power plant in Michigan, where no geothermal resource is readily available, is not feasible.[126]

Distributed Generation

Wolverine's EGAA considered potential impacts to their plan from net-metering and from distributed generation. 2008 PA 295 required utilities to allow their customers to generate their own electricity and transfer any excess electric generation, net of their own consumption, back into the electric grid. Customers with excess generation receive credit for that excess generation at the full retail rate for energy, however, the renewable energy system must be sized to meet the needs of the customer in order to qualify for net metering.

Although net-metering is required by 2008 PA 295, Wolverine states that "small net-metering installations tend to be high-cost renewable energy systems."[127] Wolverine contends that the "high cost [of small renewable energy systems] and the fact that 26 percent of the residential customers served by Wolverine's members are considered to be 'low income', it is unlikely that net metering will have a measurable effect on Wolverine's total load requirements."[128] Wolverine reported that in 2008, they had two residential customers with renewable energy systems installed that sold 7 MWh of electricity to Wolverine which met 0.0002 percent of Wolverine's requirements. Even if the number of residential customers installing systems capable of net-metering increases by a couple of orders of magnitude, it is unlikely that their contributions would have a measurable impact on Wolverine's overall energy requirements.

Distributed generation differs from net metering in that customers may generate more electricity than they need and sell the excess generation to the electric utility. Wolverine acknowledges that distributed generation has the potential to provide more impact than net-metering, however Wolverine contends that these systems are expensive and would likely only be installed by larger customers. Wolverine states that it has "an obligation to provide reliable and competitive power supply for its members' needs, today and into the future, and cannot rely on undeveloped generation by others to meet its power supply requirements."[129] Staff acknowledges that the potential impacts to Wolverine's resource plans from distributed generation is limited without additional incentives for distributed generation to be considered for installation by customers.

[126] Wolverine EGAA Appendix A-1, p. A1-22.
[127] Wolverine EGAA, p 40.
[128] Wolverine EGAA, p. 40.
[129] Wolverine EGAA, p. 41.

Combined Heat and Power

Wolverine reports that combined heat and power (CHP) technology is both feasible and commercially available. However, Wolverine reports that due to the absence of a suitable industrial partner, a CHP alternative to the proposed Rogers City plant is not suitable at this time. Wolverine does state that "future opportunities for co-location of suitable industrial partners will be evaluated and could be included in the project."[130]

While Staff recognizes the current economic situation in Michigan is unlikely to encourage investment by industrial customers in CHP, the potential for this resource to contribute to Wolverine's generation mix is noteworthy. As part of the 21st Century Energy Plan development process a CHP potentials study was performed by the Alternative Technologies CHP Team. The estimated amount of large scale CHP reported in this effort revealed a total of 720 MW of potential output. Based on a variety of limiting factors, most notably high fuel (natural gas) cost and unfavorable utility stand by rates, the Alternative Technologies CHP Team utilized a 25 percent penetration factor in their projected amount of achievable CHP resources in Michigan, yielding 180 MW of potential capacity.[131]

It should be noted that Wolverine did not provide an assessment of the potential for CHP, either for its service territory, or as a statewide assessment. Therefore it is premature to conclude that CHP would not represent a significant part of their portfolio of alternatives. While CHP (both large and small scale) may not completely replace the need for new baseload generation in Wolverine's portfolio, it can contribute towards reducing the overall amount of future capacity needed, in concert with renewable generation and energy efficiency and demand side management (DSM) programs.

Combustion Turbine and Combined Cycle

Natural gas-fired electric generation is feasible, commercially available and widely used. Wolverine reports that 41 percent of US capacity and 23 percent of generation output or energy is provided by natural gas generating units.

Natural gas powered units typically have lower capital investment costs, and shorter lead times to construct as well as high efficiency ratings as compared to typical solid-fuel generating units, and operational flexibility as they can typically be started and ramped up within minutes. The biggest drawback to natural gas-fired units is the reliance on natural gas fuel which has historically been higher priced than solid fuel options.

Combustion turbines typically have low capital investment costs, but run less efficiently than combined cycle units. Combustion turbines are typically only used as peaking generation when power demands are at their greatest levels. Combined cycle units are more efficient than combustion turbines and may run at higher capacity factors than

[130] Wolverine EGAA, p. 96.
[131] Page 149 of the 21st Century Energy Plan – Appendix II of the Final Report.

combustion turbines. Wolverine reports that most gas turbines can typically run in excess of 90 percent availability, and can achieve 95 percent availability.[132]

Natural gas units have had lower capacity factors than traditional baseload units in the past due to the security-constrained economic dispatch that is employed by the regional markets. Economic dispatch governs the electricity generation resources dispatched to supply the load on the system. Simply stated, economic dispatch is the process of distributing the required load demand among the available generation units such that the cost of operation is minimized. As such, generation units with higher fuel costs, such as natural gas-fired turbines, are dispatched less than lower fuel cost generation units, such as coal-fired boilers. Natural gas-fired turbines are typically dispatched during the peak months of the year, or when there is a constraint somewhere on the system.

Wolverine's EGAA considered natural gas-fired combined cycle units and combustion turbine units within their Least-Cost Planning (LCP) screening analysis as well as their 20-year levelized busbar cost analysis. Wolverine's LCP analysis showed that intermediate generation (based upon a natural-gas combined cycle unit) would be the optimal choice for utilizations ranging from 25 percent to 58 percent and that peaking generation (based upon a combustion turbine unit) would be the optimal choice at utilizations lower than 25 percent. From the LCP analysis, Wolverine shows that the baseload alternative is the optimal choice for higher utilization ranges. Burns and Roe agreed and states that "a natural gas-fired plan is ruled out because that fuel's volatile pricing now makes it an inappropriate choice for baseload capacity."[133]

Within the alternatives analysis, Wolverine provided the following 20-year levelized busbar costs for natural-gas fired units.

Technology Evaluated	20-Year Levelized Busbar Cost[134]
Gas Turbine Combined Cycle	9.8 cents / kWh
Gas Turbine Simple Cycle (Combustion Turbine)	11.7 cents / kWh
Wind & Gas Turbine	11.1 cents / kWh

The 20-year levelized busbar costs reported by Wolverine do not include any future costs for carbon. While natural gas-fired units typically have a smaller carbon footprint than coal-fired units, it's recommended that potential future carbon costs be included in the analysis.

Wolverine states that the capital cost assumptions for the natural gas combined cycle and combustion turbine alternatives were developed by Burns and Roe enterprises. Wolverine's natural gas price projections are based upon the EIA 20-year published projection in March of 2009. The future projected prices for natural gas, which have been volatile in the recent past, are a key factor in determining whether or not a natural-gas fired unit will be viable.

[132] Wolverine EGAA Appendix A-1, p. A1-11.
[133] Wolverine EGAA Appendix A-2, p. A2-7.
[134] Wolverine EGAA, p. 99.

Comments were received regarding excess natural gas capacity that should be utilized or purchased prior to constructing a new facility. These comments are addressed within the Purchased Power section of this report.

While natural gas units typically have lower capacity factors than traditional baseload units, they do have operational flexibility such as quick start up and ramp times. The operational flexibility that comes with natural gas units may lend itself to assisting with the integration of renewables into the electric grid more so than typical baseload units.

Nuclear

Nuclear power is feasible, commercially available, and according to Wolverine, generates 14 percent of the electric power produced in the world. Fuel costs for nuclear plants are low, and nuclear plants are designed to run at very high capacity factors making nuclear an alternative available to meet baseload needs.

Wolverine provided a 20-year levelized busbar cost estimate for nuclear at 8.5 cents per kWh.[135] Staff notes that 8.5 cents per kWh is lower than approximately half of the alternatives considered by Wolverine in the busbar analysis. Should Wolverine have included future carbon projections within the busbar analysis, nuclear would have been closer to being the least-cost alternative.

Although nuclear power may be a viable alternative in a carbon-constrained world, nuclear power was not suitable to meet Wolverine's specific needs for several reasons. Nuclear units are typically very large; usually over 1000 MW, which is significantly larger than Wolverine's reported base case need. Capital costs for nuclear facilities are very high, and there are Nuclear Regulatory Commission requirements to consider as well. Wolverine states "The siting and construction of a nuclear plant involves licensing, security, emergency planning, environmental, and socioeconomic issues that have not been studied or evaluated."[136]

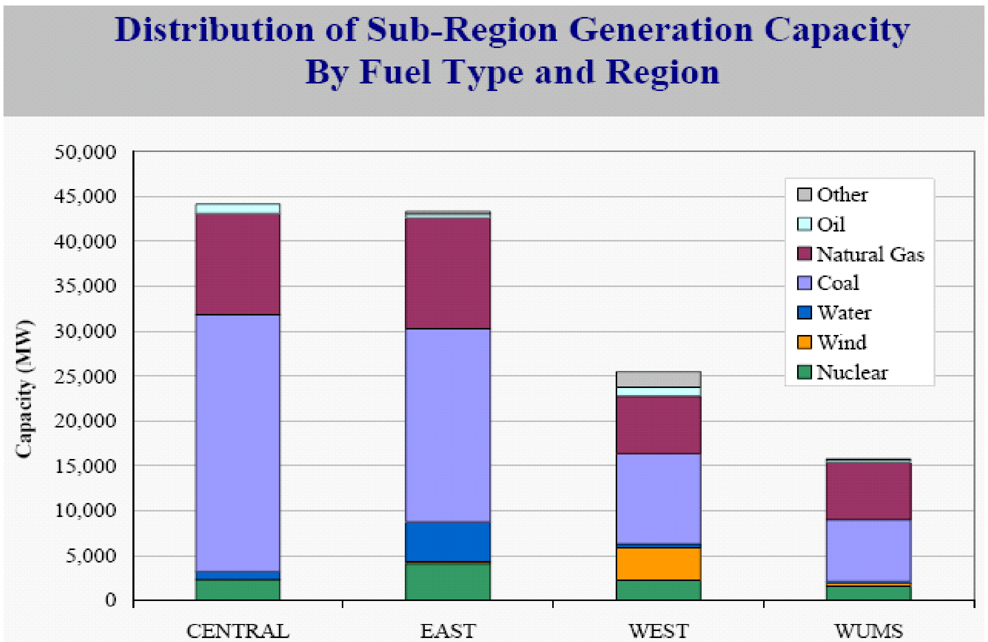
Purchased Power

Many commenter's contend that any needs that are not fully met by a combination of demand side options and renewables should be met with excess existing resources that are owned or through power purchase agreements or market purchases. Staff agrees that reliance on purchases may prove to be a viable option for the short term, but not necessarily for the long term. The Midwest ISO IMM's recently released 2008 SOM states that "Although the system's resources are adequate for the summer of 2009, new resources will be needed over the long-run to meet the needs of the system." [137]

[135] Wolverine EGAA, p. 99.
[136] Wolverine EGAA, p. 87.
[137] 2008 MIDWEST ISO IMM's State of the Market Report, MIDWEST ISO IMM SOM Report 2008, http://www.Midwestmarket.org/publish/Document/6ef35b_121e89707ed_-

Wolverine does not provide any projections for the future price of market power, nor have they considered purchased power as an option to meet their stated base case resource needs. Wolverine provides a discussion of purchased power contracts in section 5.6 of their EGAA.[138] Since the early 1970's, the utilization of nuclear and coal baseload units has increased from about 45% up to 90% for nuclear and up to 74% for coal in 2007 in the U.S. Summer reserve margins were at 40% in the Midwest region in 1981 and had dropped to 17% by 2007. In the recent past, increases in demand have outpaced resource additions and Reliability*First* is projecting that trend will continue throughout the next ten years. As the gap between supply and demand narrows, market risks and market prices increase.

Purchases in the Midwest ISO region often include coal-fired generation. The Midwest ISO IMM's SOM report details the capacity by fuel type in the Midwest ISO region:[139]



While the figure above shows the amount of capacity by fuel type, the actual generation by fuel type in 2008 was markedly different. Although approximately 52% of the capacity in the Midwest ISO is coal-fired, the Midwest ISO IMM reports that 77% of the electricity generated in the Midwest ISO region is from coal-fired units because they are typically baseloaded. Approximately 7% of the capacity is nuclear, and those units produce 15% of the energy in the Midwest ISO. Approximately 28% of the capacity in the Midwest ISO is fueled by natural gas; however, those units produce less than 5% of the energy in the region. Because the vast majority of electricity generated in the Midwest ISO region is generated using coal, reliance on power purchase agreements or market purchases in the Midwest ISO region brings on the associated risks of using a significant amount of coal-

---

7dcf0a48324a/2008%20Midwest%20ISO%20State%20of%20the%20Market.pdf?action=download&_property=Attachment, , 6/26/09, p. 55.

[138] Wolverine EGAA, p. 68, http://efile.mpsc.state.mi.us/efile/docs/16000/0001.pdf.

[139] MIDWEST ISO IMM SOM Report 2008, 6/26/09, p. 59.

fired generation. Potential cost increases for coal fired generation, and natural gas fired generation from carbon legislation may have a significant impact on purchased power prices in the future.

Some commenter's have stated that the relatively under-utilized natural gas fired generation in the region should be purchased prior to considering construction of any new facility. According to the Midwest ISO IMM's SOM report, natural gas, oil-fired and dual-fired resources set the unconstrained energy price in the Midwest ISO during 23% of the hours in 2008, however, nearly half of all real-time energy costs were incurred when these resources were on the margin. Increasing the use of natural-gas fired generation may have a significant impact on locational marginal prices in the market.

Should there be excess natural gas capacity to purchase that has not been claimed as capacity for resource adequacy needs elsewhere, contracts for that natural gas capacity may not be any more attractive for customers than reliance on the Midwest ISO market. Reliance on the energy market for purchases exposes customers to a significant amount of risk, from both higher energy prices from natural gas, and potential future costs associated with carbon legislation. Purchased Power may not be an effective long-term solution to a substantial portion of any utility's resource needs at this time, but purchased power should continue to be closely monitored and should be included as a potential short-term alternative now and in the future.

Conclusions

Staff acknowledges that a generation asset, such as has been proposed by Wolverine, represents a significant financial investment with a variety of associated risks. Significant changes have taken place on many fronts, including a slowing national and state economy, new state policy initiatives on energy efficiency and renewable energy, and pending federal legislation on the regulation of carbon emissions. With these issues in mind, Staff contends that a full spectrum of risks should have been considered within the framework of Wolverine's EGAA as it relates to long-term investment decisions of this nature.

Wolverine's EGAA filing does not constitute an Integrated Resource Plan (IRP), as outlined in 2008 PA 286, should a Certificate of Necessity (CON) be sought. Scenario analyses, using various sensitivities, including a reasonable range of values for the key input assumptions such as capital costs, fuel prices, CO_2 costs, load and energy requirements, were not conducted as part of this analysis.

In accordance with the MOU, Staff reviewed Wolverine's EGAA for the proposed coal-fired electricity generating plant to assess whether energy efficiency, renewable energy, or other alternatives meet future electricity needs. Staff provides the following findings:

- Wolverine failed to demonstrate the need for the proposed facility as the sole source to meet their projected capacity. In particular, long-term purchase power options were not fully explored as part of their analysis. It should be noted that the majority of Wolverine's long-term projected capacity need is based upon the expiration of power purchases (540 MW) on or before December 31, 2011. Wolverine has presented no evidence that the capacity currently supporting this existing contract will be unavailable in the future.
- Staff notes that the proposed CFB plant is one alternative out of a range of alternatives that may be used to fill the projected capacity need. Other alternatives that may fill all or portions of the projected capacity need include; energy efficiency and load management; renewable resources; or a combination of a number of alternatives that could include lesser amounts of purchased power.
- Further given Michigan's current recessionary condition and uncertainty concerning the time frame for recovery, Wolverine's forecasted demand growth of approximately 2.0% appears questionable, or optimistic, and the risk associated with this uncertainty was not fully addressed.

APPENDICES

A. DEQ – Commission Memorandum of Understanding (MOU)

B. Commission Order in Docket Number U-15958

MEMORANDUM OF UNDERSTANDING
BETWEEN THE
MICHIGAN PUBLIC SERVICE COMMISSION
AND THE
MICHIGAN DEPARTMENT OF ENVIRONMENTAL QUALITY

This Memorandum of Understanding (MOU) between the Michigan Department of Environmental Quality (MDEQ), and the Michigan Public Service Commission (MPSC), is entered into for the sole purpose of clarifying each agency's role and responsibility regarding the alternatives analysis review and technical assistance for the proposed coal-fired electricity generating plant applications currently pending before the MDEQ.

The MDEQ implements Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended. Part 55 is intended to protect human health and the environment from adverse impacts from the discharge of air contaminants. Consistent with state and federal law, specifically Rule 336.2817(2) of the Michigan Air Pollution Control Rules and Section 165(a)(2) of the federal Clean Air Act, the MDEQ is requesting that coal-fired power plant permit applicants conduct an analysis of alternatives to the proposed facility. The analysis will consider alternatives that would reduce emissions and will provide information regarding cost, reliability, availability, and technical feasibility of the alternatives examined.

The MPSC and the MDEQ acknowledge the benefit of clarifying each agency's role and responsibilities with respect to the alternatives analysis.

The MPSC performs the following:

- Assures the safe and reliable energy services at reasonable prices.
- Promotes the state's economic growth and enhances the quality of life of its communities through adoption of new technologies like efficient renewable energy resources.
- Provides regulatory oversight in a prudent and efficient manner while implementing legislative and constitutional requirements.

The MDEQ performs the following:

- Administers programs and enforces laws designed to protect human health and the environment from adverse impacts from the discharge of air contaminants.
- Administers an air use permitting program for the installation, construction, reconstruction, relocation, modification and operation of sources of air pollutants pursuant to R 336.1201 through R 336.1299, including coal-fired power plants.

<u>The MPSC and the MDEQ agree to the following:</u>

1. The MPSC will provide technical assistance to the MDEQ on all matters of electric generation need in the state, as it relates to determinations on the alternatives analysis.

2. The MPSC will review the alternatives analysis for the proposed coal-fired electricity generating plants to assess whether energy efficiency, renewable energy, or other alternatives meet future electricity needs.

3. The MDEQ will review the alternatives analysis for the coal-fired electricity generating plants to assess impacts of the plants and alternatives on human health and the environment.

The MPSC and the MDEQ agree to cooperate in the implementation of the provisions outlined in this MOU.

This agreement shall be effective upon the signature of both parties and remain in effect until terminated by either party. Termination may be made by either party upon 30 days written notice.

In witness thereof, the parties sign their names as evidence of their approval of this Memorandum of Understanding.

FOR THE MICHIGAN DEPARTMENT OF ENVIRONMENTAL QUALITY:

Steven E. Chester, Director — 4-1-09
Date

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION:

Orjiakor Isiogu, Chairman — 4-1-09
Date

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to establish procedures for the Commission Staff to conduct an alternatives analysis review and to provide other technical assistance to the Department of Environmental Quality pursuant to a Memorandum of Understanding between the Commission and the Department of Environmental Quality related to proposed coal-fired electricity generating plants.	Case No. U-15958

At the April 30, 2009 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Orjiakor N. Isiogu, Chairman
Hon. Monica Martinez, Commissioner
Hon. Steven A. Transeth, Commissioner

ORDER

On April 1, 2009, the Commission entered into a Memorandum of Understanding (MOU) with the Michigan Department of Environmental Quality (DEQ). An executed copy of the MOU appears as the initial entry in this docket. Reduced to its essence, the MOU constitutes a clarification of each participant's role and responsibility in satisfying the requirements regarding an alternatives analysis review and the provision of other technical assistance to the DEQ by the Commission related to the DEQ's task of issuing permits in response to applications filed under Part 55, Air Pollution Control of the Natural Resources and Environmental Protection Act, 1994 PA 451, MCL 324.101 et seq., R 336.2817(2), and Section 165(a)(2) of the federal Clean Air Act, 42 USC 7475(a)(2) for authority to construct a new coal-fired electricity generating plant.

Pursuant to the MOU, the Commission has agreed to do both of the following tasks:

1. Provide technical assistance to the DEQ on all matters of electric generation need in the state as it relates to determinations on the alternatives analysis.

2. Review the alternatives analysis for the proposed coal-fired electricity generating plants to assess whether energy efficiency, renewable energy, or other alternatives meet future electricity needs.

It will be the responsibility of the DEQ to review the alternatives analysis for the proposed coal-fired electricity generating plants to assess impacts of the plants and alternatives on human health and the environment.

Toward this end, the Commission directs the Commission Staff (Staff) to perform the following activities:

A. As required, the Regulatory Affairs Division shall open separate dockets for each investigation and shall manage the files and information gathered as part of the process. Although the investigation process established by this order will not be conducted as a contested case proceeding, the information in the dockets opened for each investigation shall be available to the general public pursuant to the Commission's e-file system.

B. The Electric Reliability Division shall assume the lead role in all technical investigations required by the MOU. The Electric Reliability Division shall contact existing DEQ permit applicants within 3 business days of the issuance of this order to inform each applicant of the review process established by the Commission. Subsequently, the Electric Reliability Division shall contact new DEQ permit applicants within 3 business days of discovery of the filing of a permit application to inform the new applicants of the review process established by the Commission.

C. Each permit applicant shall submit an electric generation alternatives analysis (EGAA) to the Commission. Each EGAA shall include all of the following information:

- Consideration of alternatives that would reduce emissions of the criteria pollutants [nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), sulfur dioxide (SO_2), lead (Pb), other hazardous air pollutants, including mercury (Hg), and carbon dioxide (CO_2)] from the proposed facility;

- The analysis should address cost, reliability, availability, and technical feasibility of the alternatives examined. Cost should be presented in a manner that facilitates a comparative analysis (i.e., dollars per megawatt-hour (MWh) for each option);

- Reduced generating capacity – description of future energy requirements and the adequacy of existing supplies. Provide the basis for the proposed design and address whether smaller boilers, a reduced number of boilers, or no new boilers are viable options in light of the other alternatives addressed;

- Improved energy efficiency at existing units – description of the energy efficiency measures available at existing units owned or controlled by the applicant to fully or partially offset the emissions from the proposed facility;

- Potential supply resources – description of the technologies considered for new generation including the consideration of renewable energy sources, clean fuels (primary fuel and fuel alternatives), and lower emitting technologies.

    - Renewable energy sources (i.e., wood, other biomass, etc.)
    - Clean fuels (i.e., low sulfur coal, etc.)
    - Lower emitting technologies
        - Natural gas
        - Wind
        - Solar
        - Hydroelectric
        - Nuclear
        - Wave Energy
        - Geothermal
        - Combined Heat and Power
        - Other innovative fuel combustion techniques
        - Cleaner technologies
        - Sequestering activities

- Demand side management/reduction – description of load management, energy efficiency, and distributed generation as a means of affecting forecasted load requirements;

- Combinations of these alternatives raised in public comments received during the DEQ public comment period.

D. The Staff and the applicant shall meet approximately 7 days after submittal of the Electric Generation Alternatives Analysis with weekly update meetings thereafter, as necessary.

E. After the filing of an EGAA with the Commission, the public shall have 30 days to comment on the filing.

F. After conclusion of the public comment period, the Staff shall within 60 days review the filed comments, continue review of the EGAA filing, perform any required analysis, and develop and prepare a report to the DEQ. In developing this report, the Staff shall give consideration to all reasonable and relevant filed comments. The applicant shall provide the Staff with any information necessary to assist the Staff in the evaluation and review of the EGAA filing.

G. In accordance with the MOU, the Staff will review the alternatives analysis for the proposed coal-fired electricity generating plants to assess whether energy efficiency, renewable energy, or other alternatives meet future electricity needs.

THEREFORE, IT IS ORDERED that the Commission Staff shall perform the tasks described in this order upon the filing of an electric generation alternatives analysis by an applicant.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

Orjiakor N. Isiogu, Chairman

Monica Martinez, Commissioner

Steven A. Transeth, Commissioner

By its action of April 30, 2009.

Mary Jo Kunkle, Executive Secretary

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-15958

County of Ingham)

Mignon Middlebrook being duly sworn, deposes and says that on April 30, 2009 A.D. she served a copy of the attached Commission orders by first class mail, postage prepaid, or by inter-departmental mail, to the persons as shown on the attached service list.

Mignon Middlebrook

Digitally signed by Mignon Middlebrook
DN: cn=Mignon Middlebrook, c=US, o=MPSC
Date: 2009.05.01 08:15:03 -04'00'

Mignon Middlebrook

Subscribed and sworn to before me
this 30th day of April 2009

Sharron A. Allen

2009.05.01
15:10:46 -04'00'

Sharron A. Allen
Notary Public, Ingham County, MI
My Commission Expires August 16, 2011

Service List U-15958

Steve Chester
Director, DEQ
Constitution Hall
525 W. Allegan St.
6th Floor, South Tower
Lansing, MI

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-15958

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on April 30, 2009 A.D. she served a copy of the attached **Commission Order (Commission's Own Motion) via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Lisa Felice

Lisa Felice

Subscribed and sworn to before me
this 30th day of April 2009

Sharron A. Allen 2009.05.01 15:08:28 -04'00'

Sharron A. Allen
Notary Public, Ingham County, MI
My Commission Expires August 16, 2011

ontrea@CHARTERMI.NET	The Ontonagon County Rea. Assoc.
akb@ALPENAPOWER.COM	No Name Available
jbedford@ALPENAPOWER.COM	No Name Available
Jackie.Seghi@CONSTELLATION.COM	No Name Available
hendersond@DTEENERGY.COM	No Name Available
armana@MICHIGAN.GOV	No Name Available
vobmgr@UP.NET	Village of Baraga
dforgacs@SEL.COM	Direct Energy Business, LLC
info@VILLAGEOFCLINTON.ORG	Village of Clinton
jepalinc@CMSENERGY.COM	CMS Energy Resource Mgt Co
Jayne@HOMEWORKS.ORG	Tri-County Electric Co-Op
mkappler@HOMEWORKS.ORG	Tri-County Electric Co-Op
patessner@HOMEWORKS.ORG	Tri-County Electric Co-Op
psimmer@HOMEWORKS.ORG	Tri-County Electric Co-Op
aurora@FREEWAY.NET	Aurora Gas Company
frucheyb@DTEENERGY.COM	Citizens Gas Fuel Company
dwjoos@CMSENERGY.COM	Consumers Energy Company
mpscfilings@CMSENERGY.COM	Consumers Energy Company
dsawruk@EDISONSAULT.COM	Edison Sault Electric Company
lbaatz@EDISONSAULT.COM	Edison Sault Electric Company
stephen.bennett@EXELONCORP.COM	Exelon Energy Company
kdcurry@AEP.COM	Indiana Michigan Power Company
jim.vansickle@SEMCOENERGY.COM	SEMCO Energy Gas Company
kay8643990@YAHOO.COM	Superior Energy Company
gericks@WPSR.COM	Upper Peninsula Power Company
ronan.patterson@WE-ENERGIES.COM	Wisconsin Electric Power Company
tharrell@CHARTERINTERNET.COM	Alger Delta Cooperative
patti.williams@BAYFIELDELECTRIC.COM	Bayfield Electric Cooperative
tonya@CECELEC.COM	Cherryland Electric Cooperative
dwozniak@CLOVERLAND.COM	Cloverland Electric Cooperative
sfarnquist@CLOVERLAND.COM	Cloverland Electric Cooperative
sboeckman@GLENERGY.COM	Great Lakes Energy Cooperative
sharone@TEAMMIDWEST.COM	Midwest Energy Cooperative
mkrause@AIRADVANTAGE.NET	Thumb Electric Cooperative
rnuss@NISOURCE.COM	Energy USA- TPC Corp
rami.fawaz@POWERONECORP.COM	PowerOne Corp
cjmiszuk@FES.COM	FirstEnergy Solutions Corp.
CommissionMail@WPSR.COM	Wisconsin Public Service Corp.
llopez@LIBERTYPOWERCORP.COM	Liberty Power Deleware (Holdings)
jlehmkuhl@NILESMI.ORG	Niles Utilities Department
kmarklein@STEPHENSON-MI.COM	Stephson Utilities Department
fzimmer@CITYOFMARSHALL.COM	Marshall Electric Dept. (Union City)
mpicklesmier@CITY-CHELSEA.ORG	Chelsea Department of Electric & Water
ktozzini@USGANDE.COM	Michigan Gas and Electric
sharonkr@PIEG.COM	Presque Isle Electric & Gas Cooperative, INC
tsobeck@PIEG.COM	Presque Isle Electric & Gas Co-op
igoodman@COMMERCEENERGY.COM	Commerce Energy
dhaubensak@CORNERENERGY.COM	Cornerstone Energy
mpscfilings@DTEENERGY.COM	DTE Energy
brian.hoeger@EXELONCORP.COM	Exelon Energy
vnguyen@MIDAMERICAN.COM	MidAmerican Energy
rarchiba@FOSTEROIL.COM	My Choice Energy
cborr@WPSCI.COM	Spartan Renewable Energy, Inc. (Wolverine Po

donald.reck@XCELENERGY.COM	Xcel Energy
cityelectric@ESCANABA.ORG	City of Escanaba
crystalfallsmgr@HOTMAIL.COM	City of Crystal Falls
felicel@MICHIGAN.GOV	Lisa Felice
bday@SPARKENERGY.COM	Spark Energy Gas, LP
nsilvestri@UNIVERSALENERGY.CA	Universal Gas & Electric Corporation
tomwhite@GLADSTONEMI.COM	City of Gladstone
rstickland@SOUTH-HAVEN.COM	City of South Haven
daustin@IGSENERGY.COM	Interstate Gas Supply Inc
hkingerski@MXENERGY.COM	MxEnergy Inc.
lanse2@CHARTER.NET	Village of L'Anse
pnewton@BAYCITYMI.ORG	Bay City Electric Light & Power
aallen@GHBLP.ORG	Grand Haven Board of Light & Power
sbn@LBWL.COM	Lansing Board of Water and Light
jreynolds@MBLP.ORG	Marquette Board of Light & Power
erice@TCLP.ORG	Traversse City Light & Power
chall@CMSENERGY.COM	CMS ERM Michigan LLC
dmzwitte@CMSENERGY.COM	CMS ERM Michigan LLC
jonesj@DTEENERGY.COM	Metro Energy LLC
bschlansker@PREMIERENERGYONLINE.COM	Premier Energy Marketing LLC
bhouse@PROLIANCE.COM	Proliance Energy LLC
rcarrier@SEL.COM	Strategic Energy LLC
nroehrs@STLOUISMI.COM	City of Saint Louis
shelm@AMERICANPOWERNET.COM	American PowerNet Management, L.P.
lturbyfill@NORDICENERGY.COM	Nordic Marketing, L.L.C.
zach.halkola@TRAXYS.COM	U.P. Power Marketing, LLC
ttarkiewicz@CITYOFMARSHALL.COM	City of Marshall
rwoller@BAARDENERGY.COM	Nordic Marketing of Michigan.com
tony@AE2.COM	Accent Energy Midwest
kunklem@MICHIGAN.GOV	Mary Jo Kunkle - MPSC
ElectricDept@PORTLAND-MICHIGAN.ORG	City of Portland
skm7@ALPENAPOWER.COM	Alpena Power
trichards@LOWELL-LIGHT.ORG	Lowell Light and Power
blefevere@CI.EATON-RAPIDS.MI.US	City of Eaton Rapids
ham557@GMAIL.COM	Lowell S.
gbass@SEMPRASOLUTIONS.COM	Royal Bank of Scotland
AKlaviter@INTEGRYSENERGY.COM	Integrys Energy Service, Inc WPSES
jcasadont@BLUESTARENERGY.COM	BlueStar Energy Services
john.gomoll@DIRECTENERGY.COM	Direct Energy Services
galvin@LAKESHOREENERGY.COM	Lakeshore Energy Services
doug.gugino@REALGY.COM	Realgy Energy Services
mrunck@VEENERGY.COM	Volunteer Energy Services
jfrench@WYAN.ORG	Wyandotte Municipal Services
kmaynard@WYAN.ORG	Wyandotte Municipal Services
rboston@SEMPRASOLUTIONS.COM	Sempra Energy Solutions
jgriffith@CI.STURGIS.MI.US	City of Sturgis
pbeckhusen@MUNI.CBPU.COM	Coldwater Board of Public Utilities
akinney@HILLSDALEBPU.COM	Hillsdale Board of Public Utilities
rjrose@HILLSDALEBPU.COM	Hillsdale Board of Public Utilities
eazimmerman@WPSR.COM	Michigan Gas Utilities
dczarnecki@CHARTERINTERNET.COM	Neguanee Department of Public Works
davidw@BPW.ZEELAND.MI.US	Zeeland Board of Public Works