Holland Board of Public Works
Electric Generation Alternatives Analysis
For Proposed Permit to Install (PTI) No. 25-07
For Circulating Fluidized Bed Coal Boiler
in Holland, Michigan

Docket Number: U-16077

Staff Report to Michigan Department

*of Natural Resources & Environment**

July 7, 2010

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Electric Reliability Division of the Michigan Public Service Commission

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Executive Summary

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

Holland Board of Public Works (HBPW) submitted its "Power Supply Study" hereafter referred to as an Electric Generation Alternatives Analysis (EGAA) to the DNRE and to the Commission on April 1, 2010. As detailed in its EGAA, HBPW is proposing to install new baseload generation that will be comprised of one 70 megawatt (net) circulating fluidized bed (CFB) boiler, and associated facilities at 64 Pine Avenue in Holland, Michigan.

Staff acknowledges that a generation asset, such as has been proposed by HBPW, 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 federal legislative efforts 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 HBPW's EGAA, as those risks should be fully considered prior to making any long-term investment decisions of this nature. In addition, the EGAA analysis should have included sensitivity analysis, to help HBPW better determine how its plan would respond to variations in basic assumptions that would affect those risks.

HBPW's EGAA filing does not constitute an Integrated Resource Plan (IRP), as outlined and required 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, carbon dioxide (CO_2) costs, load and energy requirements, were not conducted as part of this analysis.

In accordance with the MOU, Staff reviewed HBPW's EGAA for the proposed coal-fired plant to assess whether energy efficiency, renewable energy, or other equal or more cost-effective alternatives are available to meet HBPW's future electricity needs. Staff provides the following findings:

- HBPW failed to adequately demonstrate the need for the proposed facility as the sole source to meet its projected capacity requirements. Given Michigan's recent economic recession and uncertainty concerning the time frame for economic recovery, HBPW's forecasted annual demand growth rate of approximately 2.1% appears overly optimistic. Load growth in the early years is dependent upon some key industrial load additions, which have a significant impact on the overall load forecast. Furthermore, the amount of peak demand reduction potential through energy efficiency and other demand-side strategies assumed within HBPW's supply plan appears unduly conservative. Under-estimating the potential impact of energy efficiency in future years, coupled with an overly optimistic load forecast results in a projected capacity need which may not fully materialize.

- HBPW analyzed only one base case scenario in their resource expansion plans. However, one sensitivity pertaining to CO2 allowance prices was included in their analysis. HBPW acknowledged that additional sensitivities for load growth and fuel prices were not performed. Scenario analysis should be employed across a wide range of variables and sensitivities including: future load levels, fuel prices, renewable energy penetration levels, energy efficiency penetration levels, and other variables which impact future resource planning in order to properly evaluate the associated risks.

- Purchased power options were not fully explored as they were limited to only ten percent (10%) of the total requirement within the model. Staff recommends further evaluation of purchased power options that may be available to HBPW over the next several years.

- As acknowledged in HBPW's EGAA filing, 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 less costly alternatives were noted in the EGAA and could be selected to meet HBPW's expected capacity shortfall, if so desired. Other options that could fill all, or portions, of the projected capacity need include: a combined cycle natural gas plant, purchase power options or a combination of alternatives that could lead to lesser amounts of purchased power, energy efficiency and load management, and renewable generation resources.

- Staff also notes that HBPW is a municipal utility, not traditionally regulated by the Michigan Public Service Commission. As such, HBPW's Board and management are solely responsible for evaluating risk and making financial decisions for the utility and the customers it serves.

Introduction and Background

DNRE – Commission Memorandum of Understanding (MOU)

On April 1, 2009, the Commission entered into an MOU with the DNRE that clarifies each agency's role and responsibility regarding a review process to evaluate electric generation alternatives and provide technical assistance to the DNRE.

The Commission has two tasks pursuant to the MOU:

a. Providing technical assistance to the DNRE on all matters related to the need for electric generation in the state, as it relates to the analysis that evaluates alternatives to coal-fired electricity generation.
b. Reviewing the alternatives analysis to assess whether energy efficiency, renewable energy, or other alternatives can meet future electricity needs.

The MOU between the DNRE 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 proposed coal-fired electricity generating plant applications currently pending before the DNRE. The DNRE - 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 DNRE pursuant to the MOU between the Commission and the DNRE 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 DNRE by the Commission related to the DNRE'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

HBPW is a community-owned enterprise providing utility services to the greater-Holland area. HBPW provides electric generation, water and wastewater treatment services to nearly 30,000 customers. HBPW filed an Electric Generation Alternatives Analysis (EGAA) in the Commission's Docket Number U-16077 on April 1, 2010. HBPW's EGAA reports the utility has several peaking, intermittent, intermediate, and baseload resource alternatives that appear to be available to meet its projected resource need capacity until approximately 2016. These alternatives include partial ownership purchases, market purchases, along with natural gas fired combined cycle and simple cycle, supercritical pulverized coal, circulating fluidized bed, landfill gas, hydroelectric, biomass, solar PV, wave, and wind technologies.[1]

[1]HBPW EGAA, p. 1-3.

As a result of this analysis, one potential resource identified by HBPW for new baseload capacity and energy includes the proposed construction of a 78 (gross) megawatt (MW) circulating fluidized bed (CFB) boiler to be built by HBPW. Currently, HBPW is pursuing a Permit-to-Install with the Department of Natural Resources and Environment ([DNRE] formerly the Department of Environmental Quality [DEQ]) for this CFB unit. The application is a request for a plant with a maximum gross heat input of approximately 865 MMBtu/hr and includes the following air pollution control equipment: limestone injection, selective non-catalytic reduction, activated carbon injection and fabric filter. The proposed plant contains a steam turbine generator, cooling tower, and auxiliary processes and equipment to be constructed at the existing James DeYoung (JDY) Generating Station. The proposed CFB is capable of burning a variety of fuels including: coal, petroleum coke, non-construction grade wood waste, tire-derived fuel and sewage sludge. The primary fuel for the CFB is proposed to be a blend of bituminous and subbituminous Powder River Basin (PRB) coal that would supply a minimum of 90% of the total annual heat input.[2] The proposed facility would be located in Ottawa County at 64 Pine Avenue, Holland.

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 that meets the established criteria.

The findings contained in this Staff Report are limited to the scope of work described under the MOU between the DNRE and Commission and subsequent Commission Order in Docket Number U-15958. This Staff Report on HBPW EGAA (MPSC Docket Number U-16077) is unrelated to any CON hearing before the Commission. Any utility seeking to obtain a CON must do so in accordance with the rules and procedures set forth under Section 6s(10)-(11) of 2008 PA 286.

Technical Meetings

On April 16, 2010, HBPW was invited by Staff to participate in a technical forum hosted by the Michigan Public Service Commission. The purpose of this forum was to provide various environmental groups an opportunity to ask questions to HBPW regarding their filed EGAA. This type of forum was conducted with the previously filed EGAA's from Consumers Energy (Docket Number U-15996) and Wolverine Power Cooperative (Docket Number U-16000).

[2] Pending Permit to Install Applications for Coal-Fired Power Plants, http://www.deq.state.mi.us/aps/downloads/permits/CFPP/2007/25-07/Section1.pdf

On April 20, 2010, HBPW declined the opportunity to participate in a technical forum. Instead, HBPW requested to have questions submitted to the MPSC on or before April 30, 2010, posted to the docket, and then a response from HBPW would be provided within 14 days.[3] Questions were posted by the Sierra Club on April 16, 2010 and responded to on April 29, 2010.[4] Additional questions and comments were submitted and posted to the docket on this filing after the official 30-day public comment period established by the Commission for these types of proceedings.

Consideration of Public Comments

As part of the Staff analysis of the EGAA filing, public comments were evaluated and considered in terms of their relevance and merit to the alternatives analysis and within the scope of work covered by the MOU and subsequent Commission Order in Case No. U-15958. All comments submitted within the public comment period were evaluated by Staff and are contained in Docket Number U-16077 on the Commission's website.[5] The public comment period for this filing was 30 days. Comments received after the 30-day comment period were not required to be considered by Staff in the assessment and creation of this report.[6]

Interested citizens, corporations, citizen groups and other interested parties filed public comments regarding the HBPW EGAA. A range of opposing public comments was received, as well as various points of clarification. Major issues cited include, but are not limited to: the inaccuracy of the demand forecast, an incomplete filing, more cost-efficient alternatives, health effects on residents, environmental concerns, GHG emission impacts, lack of a demonstrated need for the plant, filing did not consider or disclose viable options, inconsistencies between HBPW's findings and Staff findings in previous EGAA filings, lack of transparency for modeling assumptions, analysis & data are based upon inconsistencies, and several comments suggesting that HBPW could lead Michigan's economy in clean, renewable energy.

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[3] http://efile.mpsc.state.mi.us/efile/docs/16077/0013.pdf

[4] http://efile.mpsc.state.mi.us/efile/docs/16077/0028.pdf

[5] 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=16077

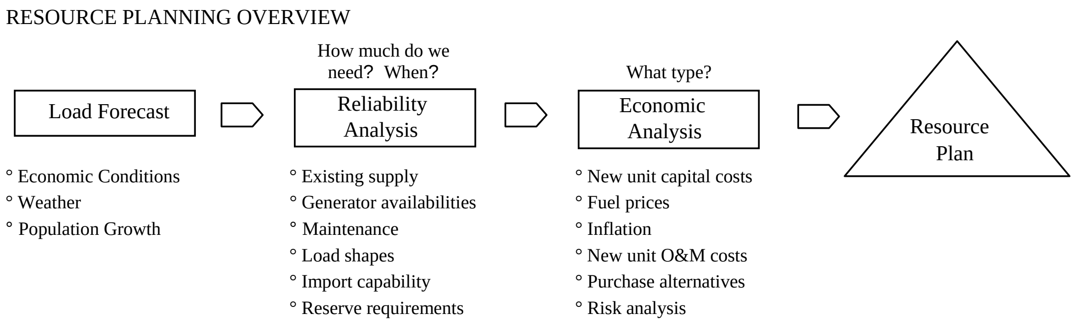
[6] Readers should note that the DNRE had a separate public comment period which is factored into its review process for purposes of this air permit application. For a list of all public comments posted on the DEQ web site for Permit to Install applicants, refer to http://www.deq.state.mi.us/aps/downloads/permits/cfpp/cfpp.htm

Regional Resource Adequacy

Planning for Reliability

For many decades, electric utilities have been planning to meet the forecasted needs of their customers. Figure 1 outlines the elements of a typical utility resource plan.

Figure 1: 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 for investor-owned utilities, 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:[7]

- Does the utility operate in a regulated, partially 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?
- Is the utility obliged to meet mandates for Renewable Portfolio Standards (RPS), Energy Efficiency Standards, or both?
- Where does demand-side management economically fit in to the portfolio?
- How will the new Clean Air Interstate Rule (CAIR) and possible greenhouse gas emission regulations affect my power supply decision?

Staff expects that utility plans filed today will address a full spectrum of risks as outlined above. While an individual utility must assess the reliability of its own supply to meet its projected loads and individual requirements, similar assessments may be completed at the state level and at the

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

regional level. This provides insight into the resource adequacy and future resource plans of the broader region in which a utility operates.

Regional Grid Operation

The Midwest Independent System Operator (ISO) was established in 1998 and approved by the Federal Energy Regulatory Commission (FERC) to be the nation's first regional transmission organization (RTO) in 2001. The Midwest ISO is the reliability coordinator in this region, which subsumes HBPW's service territory, and it manages the real-time power flow throughout the region: twenty-four hours a day, seven days a 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."[8] [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[9] (Planning Resource Adequacy Analysis, Assessment and Documentation) directs the methods and frequency for conducting assessments of resource adequacy in the RFC territory. MRO also has a similar standard for resource adequacy assessments. The Midwest ISO serves as the planning coordinator for most of Michigan, and conducts resource adequacy assessments to meet the regional reliability standards set forth by RFC and MRO. Upon completion of an updated loss of load expectation (LOLE) study, the Midwest ISO has declared a non-coincident-peak-based planning reserve margin of 11.94% for the summer of 2010 [10] for individual load-serving entities.

Adequacy in the Midwest ISO Region

The Midwest ISO annually provides a summer readiness presentation regarding the adequacy of supply in the region for the near-term summer peak. The Midwest ISO's April 2010 Summer

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[8] Economic Dispatch of Electric Generation Capacity, U.S. DOE, http://www.oe.energy.gov/DocumentsandMedia/final_ED_03_01_07_rev2.pdf, p. 2.

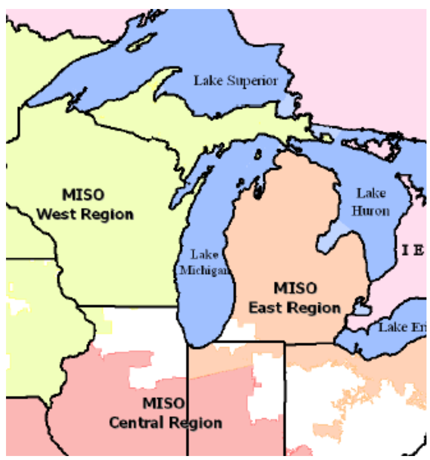
[9] Standard BAL-502-RFC-02, 12/4/08, http://www.rfirst.org/Documents/Standards/Approved/BAL-502-RFC-02.pdf

[10] Midwest Independent System Operator Planning Reserve Margin for 2010/11 Planning Year, http://www.midwestmarket.org/publish/Document/4dfde8_124a04ca493_-7f5f0a48324a/Planning%20Year%202010%20Findings_final.pdf?action=download&_property=Attachment

Readiness Presentation states "[Midwest ISO expects to have sufficient resources to reliably serve load this summer."[11] More specifically, the Midwest ISO projects a reserve margin for the 2010 summer at 25.9 percent of the estimated peak demand for the footprint.[12] Although the Midwest ISO is predicting sufficient resources for the near term, there is uncertainty surrounding long-term resource adequacy for the region.

Independent Market Monitor (IMM), Dr. David Patton of Potomac Economics, annually delivers to the Midwest ISO a State of the Market Report (SOM) which includes details that provide insight with regard to the resource adequacy of the Midwest ISO region. The IMM's 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."[13] An updated 2009 SOM was released in June 2010, and it states, "Although the system's resources are adequate for the summer of 2010, new resources will be needed over the long-run to meet the needs of the system."[14]

Figure 2: Map Highlighting Midwest ISO East Region



The Midwest ISO East region includes the majority of Lower Michigan and a small part of northern Indiana and northern Ohio.[15] The 2009 SOM also states "More than 3 GW of new capacity is expected to enter during the 2009-2010 planning year, more than half of which is

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[11] Midwest ISO 2010 Summer Readiness Workshop, http://www.midwestmarket.org/publish/Document/ff6bb_1280201754d_-7e210a48324a/2010%20Summer%20Readiness%20Workshop.pdf?action=download&_property=Attachment, April 27, 2010.

[12] Midwest ISO 2010 Summer Assessment, http://www.midwestmarket.org/publish/Document/ff6bb_1280201754d_-7db20a48324a/2010%20Summer%20Resource%20Assessment_v8_FINAL.pdf?action=download&_property=Attachment, p. 3.

[13] 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.

[14] 2009 Midwest ISO IMM's State of the Market Report, http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7aee0a48324a?rev=4.

[15] Midwest ISO Region Map, http://www.midwestmarket.org/publish/Document/254927_1254c287a0c_-7e5d0a48324a/MTEP%2009%20Report_2009-12_Final.pdf?action=download&_property=Attachment, p. 20

wind. Roughly 750 MW of generation is expected to retire. The intermittent nature of wind causes it to provide less reliability to the system than the nameplate capacity level. Although wind provides substantial environmental benefits, it also creates significant operational challenges that the Midwest ISO is working to address."[16]

Adequacy in the Reliability*First* 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:[17]

Figure 3: Map Highlighting Reliability*First* Region of NERC

Long Term Assessments of electric demand and supply are required by NERC standards. RFC's October 2009 Long Term Resource Assessment projects an increase of 23,200 MW in net internal demand for the entire region from 2009 - 2018, and an increase in net summer capacity of 12,500 MW for the same ten-year time period.[18] 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"[19]

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

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[16] 2009 Midwest ISO IMM's State of the Market Report, http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7aee0a48324a?rev=4.
[17] RFC Region Map, http://www.rfirst.org/MiscForms/AboutUs/Territory.aspx
[18] 2008 RFC Long Term Resource Assessment, October, 2008, http://www.rfirst.org/Documents/Reliability/Reports/2008%20RFC%20Long%20Term%20Resource%20Assessment.pdf, p. 2.
[19] 2009 RFC Long Term Resource Assessment, October, 2009, p. 2.

operators, such as the Midwest ISO and they are placed in an interconnection queue. Current active interconnection requests in the Midwest ISO queue[20] include:

Table 1: Current Active Interconnection Requests in Midwest ISO Queue

Proposed Generation Type	Total Midwest ISO (Nameplate MW)	Total Michigan (Nameplate MW)
Coal	3,624	1,463
Nuclear	3,418	1,589
Gas / Diesel / Co-gen	3,293	193
Wind[21]	74,201	2,513
Other Renewables	670	77

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. HBPW has not submitted a proposed capacity expansion request to the Midwest ISO as HBPW is registered in Midwest ISO as a load, which means that its generation is considered by Midwest ISO to be "behind the meter."[22] This EGAA deals specifically and exclusively with HBPW's proposed capacity expansion.

Planning in Michigan

Michigan has recently developed long-term resource adequacy plans for the state. The Commission commenced the Capacity Needs Forum23 in October 2004 to assess the adequacy of resources to meet the long-term electric needs in Michigan. Shortly following, Governor Granholm issued Executive Directive (E.D.) 2006-2 which called for the development of a comprehensive plan for meeting the state's electric power needs. Michigan's 21st Century Energy Plan24 (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 protracted downturn in the Michigan economy, which has generally lowered utility sales forecasts in Michigan. Electric plans from Michigan companies developed since the enactment of 2008 PA 295 should reflect

[20] Midwest ISO Interconnection Queue, http://www.Midwestmarket.org/page/Generator+Interconnection, Current interconnection requests included here (as of 5/10/10), are projects that are not yet in service, and those in the status categories of active, parked, or done.

[21] New Wind resources in the Midwest ISO are credited with 8% of nameplate capacity on-peak for installed reserve requirements for 2010, whereas coal, nuclear, and gas-fired units are typically credited with 100% of nameplate capacity on-peak for installed reserve requirements. http://www.midwestmarket.org/publish/Document/13b9ea_1265d1d192a_-7b910a48324a/2010%20LOLE%20Study%20Report.pdf?action=download&_property=Attachment

[22] Document 0037, response to Staff question 43

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

[24] 21st Century Energy Plan, http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm.

the requirements outlined in the Act, and should also include updated forecasts, costs, and assumptions as compared to previous plans.

Holland Board of Public Works - Load Forecast Evaluation

The load forecast for use in HBPW's planning study, through the year 2030, was prepared by Black & Veatch and was included in the HBPW EGAA filing. Black & Veatch modeled energy sales by sector based on regression analysis that examined historical utility data, economic data, and weather conditions over the period of 1981-2008. The load forecast produced projections of Total Energy Requirements, Total Energy Sales, Peak Demand and System Load Factor. The methodologies employed to model each sector are further detailed as outlined below.

Residential Sector

HBPW projected Residential sector energy sales using a basic econometric approach. The explanatory variables HBPW used to forecast Residential Energy Sales (ResMWh) include:

- The Number of Residential Customers (ResCus).
  - The values for this indicator are collected and projected by HBPW.
- Heating Degree Days (HDD[25]) & Cooling Degree Days (CD)
  - Heating and Cooling Degree Days are quantitative measures designed to capture the energy needed to heat or cool a facility. The historical and 30-year normal forecast data were acquired from the National Oceanic and Atmospheric Administration.
  - Historic Heating Degree Days for a particular month are calculated by summing, for each day of the month, the difference between 65° F and the average daily temperature day.
  - Historic Cooling Degree Days for a particular month are calculated by summing, for each day of the month, the difference between the average daily temperature and 65° F.
- Per Capita Personal Income (PCPI)[26]
- A Dummy Variable capturing the effects of recession on Residential Energy Sales.[27]
  - The years 2002, 2004, and 2008-20011 were assigned a value of 1 in the construction of the DumRec variable.
- Residential Sector Energy Price (ResP)

HBPW estimates that Residential Energy Sales will grow at a compound annual growth rate of 1.04% throughout the forecast period, growing from 165,507 megawatt-hours (MWh) in 2009 to 203,946 MWh in 2030.

[25] Document 0037, response to Staff question 16
[26] Per capita personal income statistics for the Holland-Grand Haven metropolitan statistical area, based on statistics from the U.S. Bureau of Economic Analysis, and obtained by Black & Veatch from IHS Global Insight, Inc.
[27] Use of this Dummy Variable was not mentioned in HBPW's EGAA filing, but shown in the regression output table included in *Holland's response to MPSC Staff Questions*, question 15.

Industry best practice in modeling Residential Energy Sales is to build two (2) separate models. The first would forecast the energy sales per residential customer, and the second would forecast the number of customers. The product of these two models would subsequently yield values for total Residential Energy Sales. The principle reason underlying this approach is to develop a model which avoids the spurious correlation between population growth and growth in total residential sales. In other words, isolation of the effects of possible explanatory variables such as weather indicators, income or price from the effects of population growth allow the modeler to more reliably estimate the quantitative impacts those indicators could produce. If, on the other hand, these values are estimated using a model that explicitly accounts for population growth, the traditionally close relationship between population growth and electricity sales growth can cloud the true effects of the other indicator variables and lead to a model which provides superficial results.

Staff comments that while Black & Veatch's high R-Squared value indicates a significant fit, the independent variables CDD, HDD, PCPI, ResP, Dummy Residential Recession, and the modeling constant are all independently insignificant by t-test at the 5% significance level. This indicates that Black &Veatch's residential model likely suffers from the spurious correlation problem described in the previous paragraph. While the Black & Veatch model indicates a strong fit, the strength of the fit is likely driven by direct inclusion of population growth within a single model.

Commercial and Industrial Sectors

HBPW combined Commercial and Industrial (C&I) Sector Sales into one projection due to the recent reclassification of C&I accounts. The independent variables included in the C&I Energy Sector autoregressive function are:

- Gross State Product of Michigan (GSP)
- Commercial and Industrial Energy Sales lagged one period ($CIMWh_{t-1}$)
- Energy Intensity (Eng_Int)
    - Energy intensity is a measure of energy consumption per dollar of gross domestic product (GDP).[28]
- A Dummy Variable capturing the effects of the current recession on C&I energy sales (Dum_Rec)
    - The years 2002, 2004, and 2008-2011 were assigned a value of 1 in the construction of the Dum_Rec variable.

C&I energy sales are predicted to grow 2.4% annually from 747,614 MWh in 2009 to 1,201,954 MWh in 2030.[29] Much of the growth in the C&I energy sector is attributed to a projected expansion in the manufacturing sector, planned to be operational in the HBPW area starting in 2014. This planned expansion in the manufacturing sector is comprised mainly of two (2) Lithium-ion battery plants to be located within the HBPW service territory, as well as expansion

[28] HBPW EGAA, p. 3-2.
[29] Forecast results are shown in Table 3-1 of the HBPW EGAA, U-16077.

of an existing HBPW customer.[30] HBPW states that in 2014 the planned C&I expansion will account for 20.7% of C&I Energy Sales.

Staff notes that the independent variables GSP and DumRec are not statistically significant by t-test at the 5% level. In the case that these variables were used to measure marginal effects on C&I Energy sector sales, the results obtained from this model would be inconclusive. However, in this case, C&I sales are forecasted by the complete set of included explanatory variables.

Therefore, the inclusion of independently insignificant variables does not necessarily detract from the overall effectiveness of the model. The use of independent variable Eng_Int within the C&I model is unclear. While listed in the form model on page 3-2 of the HBPW EGAA, it is not included in the regression output table included in Question 15 of HBPW's response to Staff questions.[31] These inconsistencies should be adequately addressed before judgment of the validity of the submitted regression analysis can be made.

Other Sector

The Other Energy sector sales (primarily street lighting) are forecasted by an autoregressive function, similar to the model used in the C&I sector. The independent variables used in the model include:

- The Number of Residential Customers (ResCus)
- Other Energy Sales lagged one period ($OMWh_{t-1}$)
- A Dummy Variable for 1998
    - A dummy variable was included in the model to remove the effects of an outlier in the Other Energy Sales data.[32]

Other energy sales were predicted to grow at 0.376% annually, reaching 3,886 MWh in 2030.

Total Energy Sales & Total Energy Requirements

Total Energy Sales were calculated by summing the Residential, C&I, and Other Energy Sector Sales, as well as planned future additions to the C&I sector. Estimated effects of sales reductions resulting from HBPW's energy efficiency programming were not included in these projections. Total Energy Requirements were calculated base on the Total Energy Sales plus an additional requirement to cover system losses, which HBPW projects[33] to be 3.4% throughout the forecast period.

[30] Document 0028, response to Sierra Club question 8
[31] Document 0037, response to Staff question 15
[32] Document 0037, response to Staff question 14
[33] HBPW EGAA, p. 3-1 shows projected system losses to be 3.6%. HBPW EGAA Table 3-1 on p. 3-4 shows projected system losses at 3.4%.

Figure 4: Historical and Forecasted Energy Sales and Total Energy Requirements

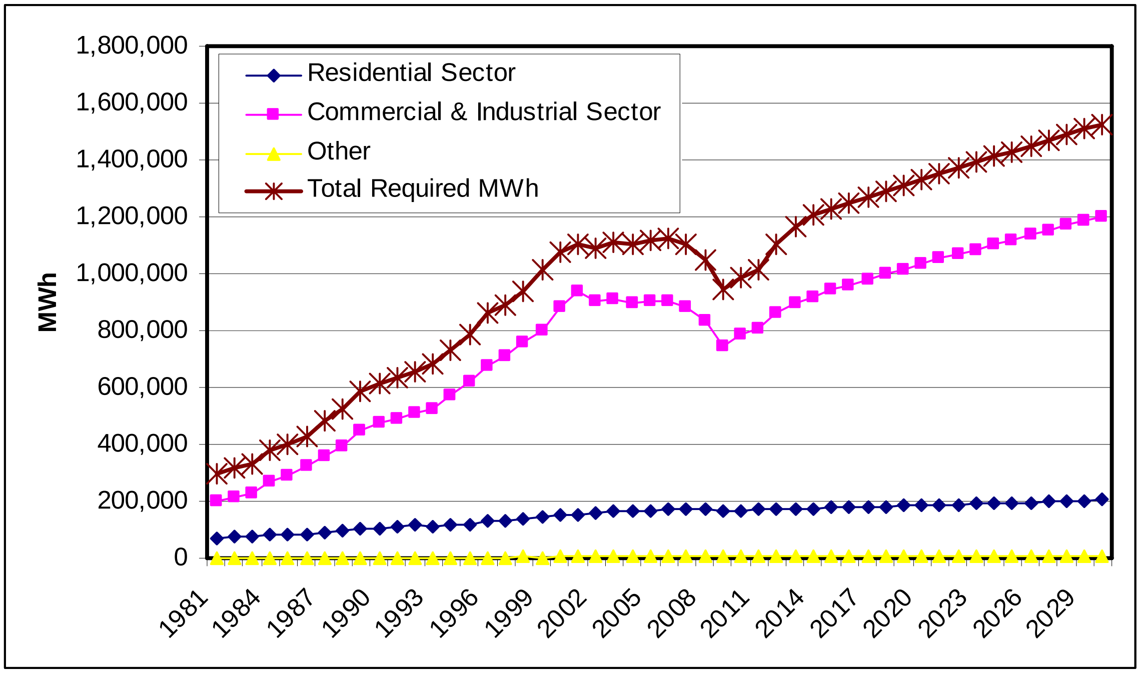

Figure 4 above shows the historical and forecasted energy sales by sector, as well as the Total Energy Requirements (Total Required MWh) values through 2030.

Peak Demand

HBPW creates Peak Demand projections through algebraic manipulation of the definition of Load Factor. Load Factor is defined as Total Energy Sales (MWh) divided by the product of Peak Demand (MW) and the number of hours in one year (8760). Solving for Peak Demand yields the following formula:

$$PeakDemand = \frac{TotalEnergy(MWh)}{(LoadFactor)(8{,}760hrs)}$$

Inputting Load Factor projections derived from historical utility data and Total Energy Requirements from econometric load forecasting results in a peak demand schedule for each year in the forecast period.

HBPW predicts summer peak electricity demand in its service territory to grow at an annual rate of 2.117% from 204 MW in 2009 to 308 MW in 2030. Compared to the most recent peak load forecast, performed by R.W. Beck, Inc., in its Integrated Holland Load Forecast (2003), the current forecast is significantly lower. The discrepancy between these forecasts is principally due to the current economic recession. HBPW did not provide confidence intervals, either probabilistic or scenario-based, in the peak demand forecast section of its EGAA filing.

In addition, public comments received contend that HBPW forecasts an unrealistically high load growth rate throughout the planning period.[34] As shown by Figure 4, HBPW's electricity sales grew at a compound annual growth rate of 1.1%[35] from 1999-2007. This modest load growth preceded the substantial decrease in electric power demand that is attributed to the recession of 2008-2009. Therefore, it is possible that future load growth could return to a similar trend in the foreseeable future.

Staff notes that the peak demand growth rate projection prepared by Black & Veatch for the HBPW service territory, 2.117%, is almost three times higher than the annual load growth rate projected for the Midwest ISO region, approximately 0.72%.[36] HBPW asserts that much of the future growth in peak demand is attributed to planned expansion in the C&I sector.

Table 2: Average Peak Demand Growth from 2010-2030[37]

Years	Average Change in Peak Demand (%)
2010-2014	3.8%
2015-2019	1.7%
2020-2024	1.4%
2025-2030	1.3%

Table 2 shows the average peak demand growth rates in five year blocks throughout the forecast period. The planned C&I expansion is expected to begin in 2010, and becoming fully operational by 2014. In this time period, as expected, HBPW forecasts a relatively high peak demand growth rate of 3.8%. From 2015-2030 however, HBPW forecasts peak demand growth continuing at approximately twice the annual 0.72% projected for the Midwest ISO region. Staff observes that even after the planned C&I expansion is accounted for, HBPW's peak demand growth projections continue to be significantly greater than the estimates for the Midwest ISO region provided by Black & Veatch. The discrepancy between HBPW and Midwest ISO projections does not necessarily indicate that HBPW is incorrect, but it does merit special consideration in light of these various factors.

Net Peak Demand Forecast

HBPW's Net Peak Demand Forecast incorporates peak savings associated with Energy Efficiency (EE) and Demand Side Management (DSM) as outlined in PA 295 for the years 2010-2015, holding system load factor constant at 56.4%. Reductions to peak demand for 2016 through 2030 "incorporate EPRI's RAP [realistic achievable potential] DSM savings forecast for peak demand."[38] Assumed reductions to HBPW's peak demand from demand side alternatives included within the EGAA are tabulated below.

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[34] Comments of Schlissel on p. 38, Document 0034, 4/30/10: http://efile.mpsc.state.mi.us/efile/docs/16077/0034.pdf
[35] HBPW EGAA, Table 3-1.
[36] EGAA, Appendix A. Staff computed Peak Demand growth rate by estimating values from table on p. 189.
[37] Figures in Table 2 are adapted from HBPW EGAA, Table 3-1.
[38] HBPW EGAA, p. 3-11.

Table 3: HBPW's Assumed Reductions to Peak Demand

Year	Peak Demand Before DSM Savings[39]	Peak Demand Adjusting for RAP DSM Savings[40]	Calculated Peak Reduction
2015	250 MW	230 MW	8.0 %
2030	308 MW	287 MW	6.8 %

A more detailed discussion of energy efficiency and demand side strategies are included within the Alternatives Analysis section of this report.

Load Forecast Uncertainty

As is common in load forecasting, HBPW's econometric models assume fixed values for various indicators. In reality, these indicators are themselves estimates and carry with them inherent degrees of uncertainty. This necessary adaptation limits the quality of risk assessment traditionally provided by calculated confidence intervals.[41] Confidence intervals, by definition, provide a range of values in which the estimated parameter is likely to fall. As noted in *HBPW's Response to MPSC Staff Questions*,[42] HBPW did not include statistical or scenario based confidence intervals in its EGAA filing. Staff comments that multiple demand-side forecast scenarios modeling various load growth trajectories should be analyzed in order to fully evaluate the risks associated with the application of HBPW's econometric load forecast for the purpose of resource planning. As uncertainty exists regarding the time frame and progress of economic recovery in Michigan, the potential for significant variance between forecasted and actual demand for energy, would necessitate accounting for such risks in the planning process.

Holland Board of Public Works – Resource Needs Evaluation

To ascertain HBPW's need for power, a forecast of system peak demand, adjusted for DSM, was developed through 2030, as previously described. In 2010, HBPW will have about 273 MW of available summer capacity from its existing resources and power purchase agreements (PPA's) including:

- James De Young Generating Station: coal-fired electrical generating units, JDY Units 3, 4, and 5 (56 MW total)
- 48th Street Generation Station: natural-gas fired simple cycle combustion turbines, two of which are capable of burning distillate fuel oil as a secondary fuel source, CT7, CT8 and CT9 (147 MW total)

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[39] Document 0028, response to Sierra Club question 12
[40] Document 0053, response to Staff question 2
[41] Veall, Michael R. *Bootstrapping the Probability Distribution of Peak Electricity Demand*, International Economic Review, vol. 28, no. 1,Feburary 1987, p. 203-212
[42] Document 0037, p. 3

- 6th Street Generation Station: simple cycle combustion turbine that operates on distillate fuel oil, CT6 (18 MW)

HBPW owns a share of the coal-fired electrical generating Unit 3 at the J.H. Campbell Plant (10.57 MW net summer capacity) operated by Consumers Energy Company and Units 1 and 2 at the Belle River Plant (35.65 MW net summer capacity) operated by Detroit Edison Company.[43] In addition, HBPW uses various sources of short-term and long-term purchased power to meet demand. Existing calendar-year 2010 PPA's entered into with wholesale suppliers through Michigan Public Power Agency (MPPA) include:

- Purchase 15 MW in calendar year 2010
- Purchase 25 MW in calendar year 2010
- Sale of 26 MW (capacity only, no energy) through May 31, 2010[44]

Finally, HBPW intends to satisfy the renewable energy requirements of 2008 PA 295 through existing and potential future renewable energy sources including:

- Grayling Generating Station: biomass fueled power plant (9,461 MWh: PPA expires in 2014)
- Granger Landfill Energy: several landfill gas energy projects owned by Granger (20 year PPA, starting in February 2010, increasing from 780 kW in 2010 to 3.4 MW in 2014)
- North American Natural Resources (NANR): landfill gas energy project owned by NANR (20 year PPA, starting in January 2010, increasing from 4.3 MW in 2010 to 6.4 MW by 2018)
- Civic Center Wind: 1, 1.5 kW wind turbine and 1, 1.9 kW wind turbine located at the Holland Civic Center (20 percent capacity factor assumed)
- HBPW Service Center Wind: 1, 1.5 kW wind turbine located at the HBPW Center roof (20 percent capacity factor assumed)

Future renewable energy expansion plans include additional wind resources.[45]

Resource adequacy planning is planning for reliability, as previously described in this staff report. Load-serving entities in the Midwest ISO region are required to meet the requirements of the Midwest ISO's transmission and energy markets tariff. HBPW assumed a 12 percent reserve margin of capacity for planning in the summer season to cover uncertainties such as extreme weather, forced outages for generators, and uncertainty in load projections. The assumed reserve margin of 12 percent is very close to the Midwest ISO Module E requirement of 11.94 percent for the summer of 2010.

HBPW's projected resource needs are depicted in Table 4-1 of its EGAA filing. Inputs into the resource adequacy calculation include the forecasted peak demand that has been reduced based

[43] HBPW EGAA, p. 2-1 and 2-2.
[44] HBPW EGAA, p. 2-3 and 2-4.
[45] HBPW EGAA, p. 2-4 and 2-5.

upon DSM assumptions, the reserve margin, owned generation, capacity purchases and capacity sales.

If no capacity is added during the entire planning period, HBPW contends it will need additional capacity from 2016 through the entire planning period to meet its reliability criteria. In 2027, the installed capacity would fall below the system peak requirements. The capacity shortfall to meet reliability criteria starts at 1.3 MW in 2016 and would increase to 43.7 MW in 2030, if no capacity additions were made.[46] The next step in the electric infrastructure planning process would be to determine what type of capacity is needed in order to meet the total load demand for all hours, at the least cost.

Public comments assert that HBPW's assumptions for new generation is constructed on the basis of a number of uncertainties. Given the tenuous economic times, there is no certainty that the forecasted loads and energy sales will materialize. Furthermore, existing state and/or new federal renewable/energy efficiency standard could substantially change the focus of HBPW generation needs.

Holland Board of Public Works – Resource Planning Methodology

Black & Veatch conducted an analysis of various renewable and conventional generation technologies. In summary, each technology was evaluated with respect to its operating principles, applications, resource availability in Michigan, cost and performance characteristics, and environmental impacts. Black & Veatch estimated technology costs and performance parameters based on project experience, past vendor inquiries, and a literature review.[47] Further details regarding the screening of various technologies can be found in the Alternatives Analysis section of this report.

Strategist, a capacity expansion optimization computer model, was used by Black & Veatch to evaluate combinations of resources available to HBPW to meet future demand and energy requirements over a 20-year period from 2010 through 2029. A typical week in each month of the year over the planning period is assessed by Strategist to optimize, based on estimates of annual total system costs, the least-cost generation alternatives. This analysis includes such factors as peak demand, energy needs, fuel and emissions prices, fixed and variable operating costs and capital costs.[48]

Numerous assumptions were incorporated into the required modeling inputs. These inputs included performance characteristics of generating units, fuel costs, fixed and variable operations and maintenance (O&M) costs, emission rates and costs, demand and energy charges for purchase power resources, capital costs for future resource additions, system load profile, and projected capacity requirements including reserves. HBPW supplied Black & Veatch with data for its existing resources and some of the proposed new resources that were considered in the analysis. For future generic generation alternatives, Black & Veatch provided the operating and

[46] HBPW EGAA, Table 4-1, p. 4-3.
[47] HBPW EGAA, p. 5-1.
[48] HBPW EGAA, p. 7-1.

cost data.[49] In addition, HBPW has indicated that it has procured or is in the process of procuring all resources necessary to meet its requirements until 2015. As such, Black & Veatch assumed energy and capacity market purchases were solely available to meet the HBPW needs until 2015. Spot market purchases were assumed to meet up to 10 percent of HBPW's need since HBPW has historically owned more than 90 percent of its capacity needs.[50] Further details regarding the assumptions that went into the modeling effort can be found throughout HBPW's EGAA report.

Strategist was utilized to evaluate all combinations of generating unit alternatives, renewable resources, and purchase power options along with existing generation resources while maintaining user-defined reliability.[51] Evaluated generation alternatives included landfill gas, wind, biomass, natural gas combined cycle and combustion turbines, supercritical coal, circulating fluidized bed (CFB), and market purchases.[52] The operation of a power supply system was simulated over the 20-year planning period by economically dispatching available resources to meet the projected capacity and energy requirements. Strategist took into account variable O&M, emission costs, and fuel costs when determining the dispatch order for available generating resources.[53] With the exception of self-built plants that would be built somewhere within the HBPW system, Black & Veatch considered transmission cost adders in all scenarios.[54] The total annual system costs and the cumulative present worth cost (CPWC) of each expansion plan were calculated by Strategist. The capacity expansion plan with the lowest CPWC is considered the least-cost capacity expansion plan.[55]

As explained later, Black & Veatch identified base case capacity expansion plan alternatives for the HBPW. These alternatives were evaluated using a carbon dioxide (CO_2) price forecast resulting in a significant impact on energy prices. From these alternatives, four were selected for further evaluation, including consideration of no CO_2 allowance prices.[56]

Carbon Risk

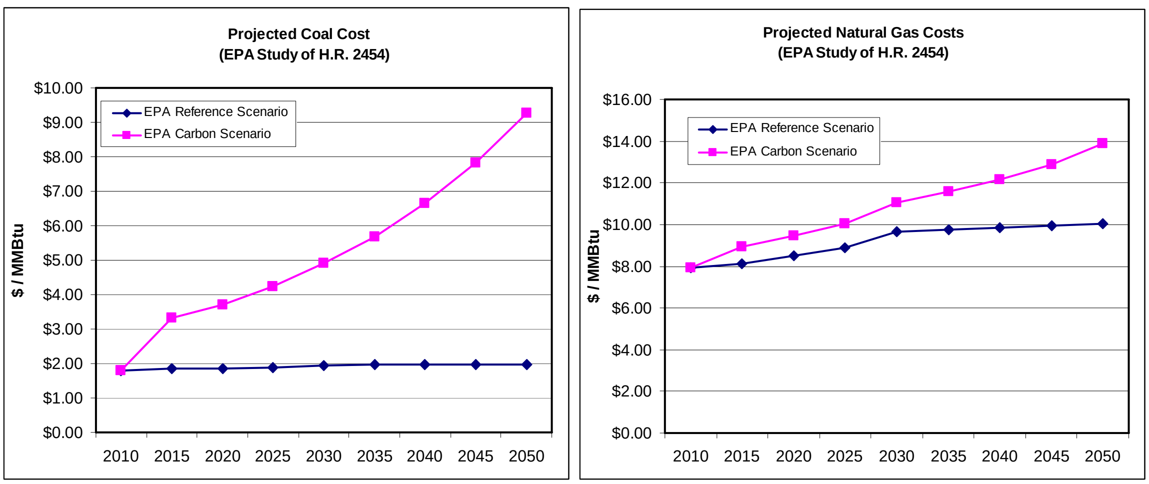
The carbon dioxide emission allowance scenario employed by Black & Veatch for purposes of HBPW's EGAA filing assumes a cap and trade regulatory structure taking effect in 2014, where carbon dioxide producers will pay a discrete fee per ton of CO_2 emitted. Black & Veatch analysis assumes an initial allowance of $22/ton of carbon dioxide equivalent (CO_2e),

[49] HBPW EGAA, p. 7-3.
[50] HBPW EGAA, p. 7-2.
[51] HBPW EGAA, p. 7-1.
[52] HBPW EGAA, p. 1-3.
[53] HBPW EGAA, p. 7-2.
[54] HBPW EGAA, p. 7-7.
[55] HBPW EGAA, p. 7-3.
[56] HBPW EGAA, p. 7-18.

growing at an annual rate of 8.8% to \$86/ton of CO_2e in 2030. The cap and trade greenhouse gas (GHG) regulation assumptions employed by Black & Veatch in this study are based one of many potential GHG regulatory structures, the American Clean Energy and Security Act[57] (H.R. 2454 Waxman-Markey), which intends to set standards for significant reduction of global warming pollution.

Although a cap and trade mechanism such as H.R. 2454 is only one of many potential regulations, the United States Environmental Protection Agency (EPA) recently conducted a study of the potential impacts of the bill on fuel prices.[58] The graphs in Figure 5 below depict one scenario (Scenario 8)[59] modeled by the EPA showing a potential rise in fuel prices from the proposed cap and trade carbon legislation versus a reference case which assumes no carbon legislation through the analysis period. Scenario 8 assumes a carbon cap and trade system taking effect in 2015 with a carbon allowance of \$15.77/ton CO_2e, and growing 5.05% annually to \$33.03/ton CO_2e in 2030.

Figure 5: Comparison of Coal Cost vs. Natural Gas Cost



The area between the two curves in each graph in Figure 5 depicts the potential risk in future coal and natural gas prices due to the proposed H.R. 2454 legislation, as modeled by the EPA. In addition to increases in fossil fuel costs, carbon legislation may also lead to higher electricity prices from producers that burn fossil fuels and emit CO_2, which will in turn be passed on to the consumer. Additionally, future investment in carbon capture and sequestration may also need to be made in order to comply with such future regulation. While the future of CO_2 regulation in the U.S. is still uncertain, Staff concludes that further sensitivity analysis of the potential variation in commodity costs under a cap and trade GHG regulation should be included in HBPW's EGAA. As previously noted, Black & Veatch assumed a carbon tax of \$22/ton CO_2e

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[57] An official summary of H.R. 2454 can be downloaded here: http://energycommerce.house.gov/Press_111/20090331/acesa_summary.pdf

[58] EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress, 1/29/2010, http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf

[59] EPA's Scenario 8, EPA's H.R. 2454 analysis, data annex, ADAGE model results, p. 10, http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf

in 2014 and rising to $86/ton CO_2e in the development of its busbar cost analysis for coal and natural gas-fired technologies.

North American Coal Outlook

The predicted delivered PRB coal cost projection included in the HBPW's EGAA filing are based on analysis and modeling provided by Black & Veatch. This coal price forecast represents the price of PRB coal delivered to a generic plant in Michigan.[60] It incorporates both the cost of mining and transportation by rail. HBPW assumes that the delivered cost of coal from the Wyoming PRB will grow at a compound annual growth rate of 2.5%, reaching a price of approximately $3.41/MBtu in 2030.

Figure 6 below compares,[61] in nominal dollars, the coal price forecast employed by Black & Veatch, the EPA's base case (no carbon emission regulation), and a coal price scenario analysis performed by the EPA[62] under a hypothetical carbon emissions cap and trade regulatory structure. The EPA's January 2010 supplemental analysis to the proposed American Clean Energy and Security Act of 2009 (H.R. 2454)[63] specifies various potential GHG emission regulation scenarios, and investigates the economic impacts of each case. Scenario 8 represents a carbon tax scenario where CO_2 producers would be required to pay $15.77 - $33.03 per ton of CO_2 emitted in the years 2015-2030, respectively. Under such legislation, EPA analysis implies that the price of delivered coal will likely increase throughout the foreseeable future. The EPA's base case scenario projects the national average delivered coal price absent any effects of carbon emission regulation.

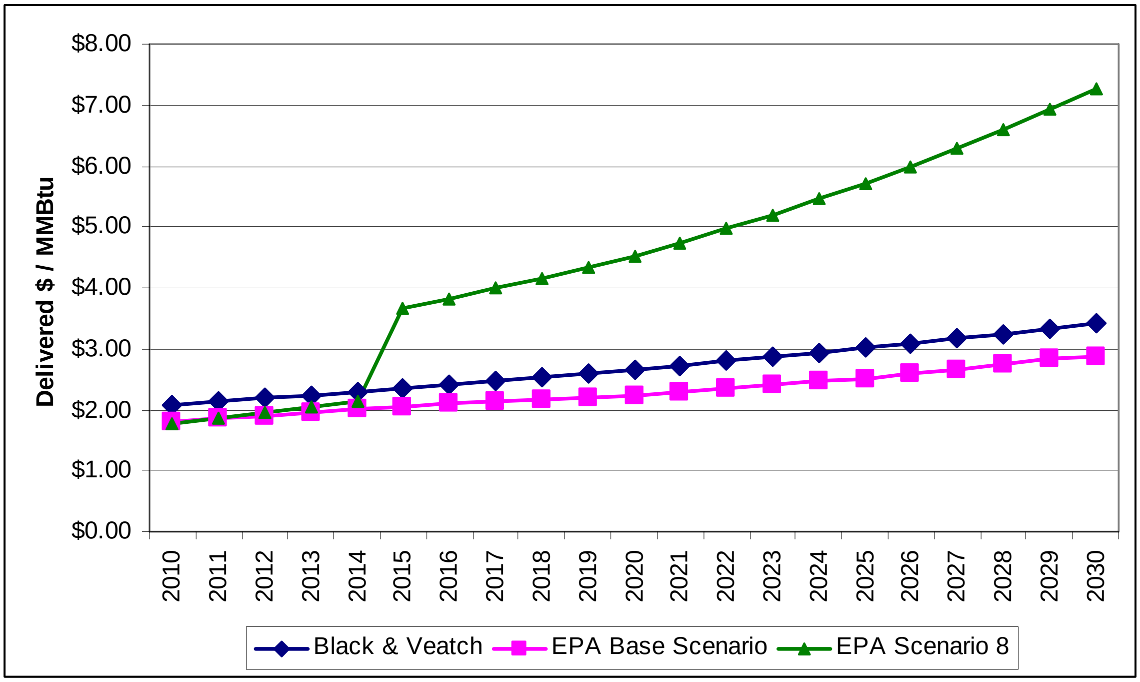
[60] HBPW EGAA, p. 6-1

[61] The purpose of Figure 6 is to show the volatile effects of potential GHG emission regulation on coal prices. It does not provide an assertion regarding the validity of the coal price forecast provided by Black & Veatch.

[62] EPA's coal price forecasts were based on national average coal prices in the ADAGE data annex to the *EPA Analysis of the American Clean Energy and Security Act of 2009.* Staff adjusted EPA's national average coal prices to an estimated equivalent PRB price using EPA commodity figures in the EPA IPM regional coal price projections and the 21st CEP transportation costs.

[63] Additional information: http://www.epa.gov/climatechange/economics/economicanalyses.html

Figure 6: Coal Price Forecast (Nominal Dollars[64])



The area between the two EPA scenario curves (EPA Base & EPA Scenario 8) in Figure 6 above depict the volatile effects of potential GHG regulation on the future market price of coal.

It should be noted that production costs of PRB coal are projected to steadily increase throughout the forecast period, invariant on potential GHG emission regulation.[65] Under a potential regulated carbon emission structure, Staff would expect to see a significant upward shift in the delivered price of PRB coal, most likely attributed to the increase in production and transportation costs. Efficient resource planning requires the consideration of multiple coal price projections under varying GHG regulation scenarios in order to determine the impact of higher than expected coal prices on marginal base load electricity costs, dispatch order, and expected capacity factors. While the future of GHG regulation is still uncertain, Staff concludes that without performing such scenario analyses, it is inherently risky to undergo resource planning without considering the volatile effects of potential future greenhouse gas legislation on commodity prices.

North American Natural Gas Outlook

The predicted delivered natural gas cost projection included in the HBPW EGAA[66] filing is based on analysis and modeling provided to HBPW by Black & Veatch for the purposes of Commission Case U-16077. Black & Veatch estimates that natural gas prices will increase at a compound annual growth rate of 5.9% throughout the forecast period, converging at a price of

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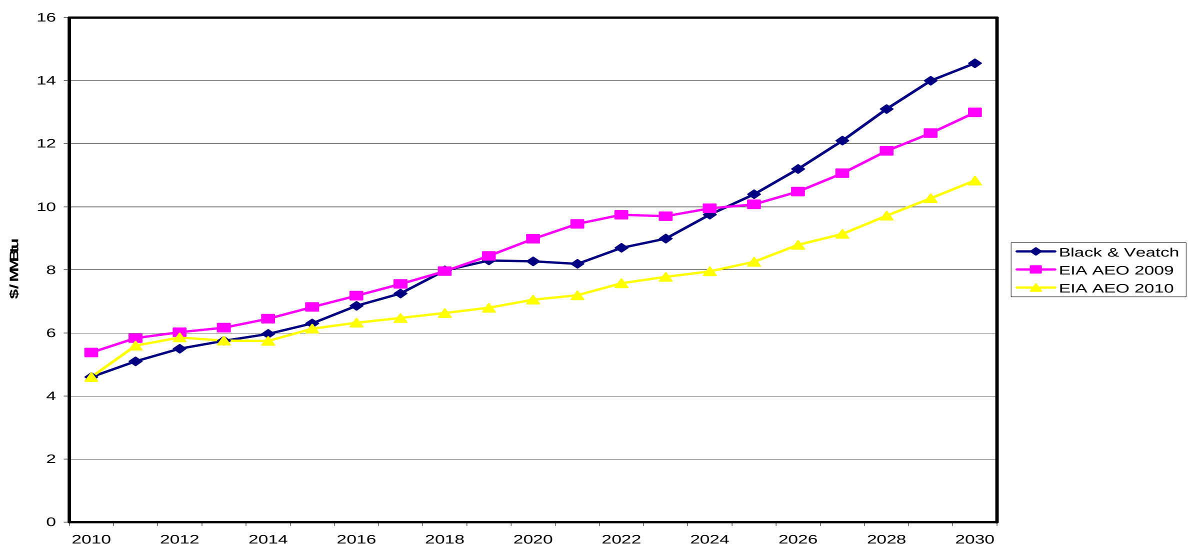
[64] EPA estimates are reported in real 2008 dollars. These figures are converted to nominal values assuming an annual inflation rate of 2%.
[65] EIA, *Annual Energy Outlook 2009*, p. 83-84
[66] HBPW EGAA, p. 6-2

approximately $14.55/MMBtu in 2030. This projection is comparable to the EIA's delivered natural gas price forecast included in its *2009 Annual Energy Outlook.* However, in its *2010 Annual Energy Outlook,*[67] the EIA projection for delivered natural gas prices is significantly lower than projections made in 2009. This discrepancy is likely attributed to the growing interest and expertise in shale gas recovery technology and speculation, as well as increased estimates of technically recoverable reserves. Figure 7[68] below compares the projected natural gas prices, in nominal dollars, between the AEO 2009, AEO 2010, and the projection made by Black & Veatch for the purpose of the HBPW EGAA filing.

Figure 7: Natural Gas Price Forecast (Nominal Dollars)



Key Observations

Throughout the EGAA report, various data about specific technology options was provided by HBPW. The intent seemingly was to illustrate estimated operating characteristics, resource availability and other factors related to each option, ultimately leading to cost estimates for such resources, whether installed in the HBPW service territory or elsewhere.

Several public comments noted the lack of details made available in the HBPW filing, including work papers and specific data, related to the various analyses conducted as part of the resource planning process. Comments along these lines were received from the public and other interest groups and all express some level of frustration with the lack of available data. The grievances generally complained of the inability to independently review and question HBPW's key assumptions about alternative energy technologies. Public comments contend that the HBPW provided only limited information and no workpapers or computer input and output files in support of the conclusions presented in the EGAA.

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[67] Natural gas price projections by region can be downloaded at: http://www.eia.doe.gov/oiaf/aeo/supplement/sup_ogc.xls#set5.1118a!C1002

[68] EIA *Annual Energy Outlook* price projections are reported in real 2008 dollars. In order to provide a normalized comparison, these prices are converted to nominal dollars, assuming an annual inflation rate of 2%.

Through the discovery process, Commission Staff asked HBPW to provide supporting information needed in order for Staff and the interested parties to thoroughly understand the assumptions and resulting outcomes. The response to these requests generally was "models used to calculate the levelized costs are proprietary to Black & Veatch,[69] and data for cost estimates is maintained in Black & Veatch's proprietary databases."[70]

The importance of transparency throughout the analysis of the EGAA is essential due to the fact that prices, technology, and availability of resources constantly changes. Staff agrees with the many public comments that transparency regarding all important modeling assumptions should be a major component of final report presentation. Staff also agrees that the lack of transparency is a shortcoming of this particular filing. Staff believes that the desired transparency regarding modeling assumptions is necessary for the EGAA review, especially because the time available for the EGAA review and analysis is so brief (90 days).

In addition, a few public comments claimed the EGAA findings are inadequate and inconsistent in comparison to the Commission's findings of Wolverine and Consumers Energy's EGAA. Staff discovered that existing sources, energy efficiency and renewable electric generation sources could meet the needs of these much larger utilities.[71]

As also noted in public comments, scenario analysis including a reasonable range of values for key input assumptions such as capital costs, fuel prices, CO_2 costs, load and energy requirements were not conducted. Staff also notes that energy efficiency and demand side options were at a fixed level at the single scenario initially modeled regardless of supply-side avoided costs. The Strategist modeling analysis did not adequately consider significant risks and uncertainties that HBPW would face in building and operating the proposed CFB coal plant through conducting sensitivity analyses based on changes in key input assumptions.

Specifically, no sensitivity analyses were performed for higher construction costs, a range of CO_2 costs, higher or lower natural gas or coal prices, or a higher energy efficiency investment, as an option on its own, or as part of a portfolio with increased investments in renewable resources and/or a smaller natural gas-fired unit. Furthermore, the Strategist model appears to not have included the option of choosing mid- or long-term power purchases from existing and under-utilized gas-fired units in and around the state of Michigan, either on its own, or as part of portfolios with other resources such as energy efficiency and wind generation.[72]

HBPW's EGAA falls short of presenting 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, uncertain forecasted demand and regulatory uncertainty appears 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

69 http://efile.mpsc.state.mi.us/efile/docs/16077/0028.pdf
70 http://efile.mpsc.state.mi.us/efile/docs/16077/0037.pdf
71 http://efile.mpsc.state.mi.us/efile/docs/16077/0019.pdf
72 http://efile.mpsc.state.mi.us/efile/docs/16077/0034.pdf, p. 27 & 28/95

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.

Of particular noteworthiness on this subject, Consumers Energy recently announced postponement of constructing its proposed 830 MW coal plant in Michigan "because of reduced customer demand for electricity due to the recession, forecasted lower natural gas prices due to recent developments in shale gas recovery technology, and projected surplus generating capacity in the Midwest market."[73]

Holland Board of Public Works - Alternatives Analysis

Proposed Generation Alternatives

As previously indicated, Strategist was used to estimate the total annual system costs and to estimate the cumulative present worth cost for each expansion plan. Table 4 identifies the ten least-cost expansion plans selected for the HBPW along with its respective CPWC values and its 20 year levelized cost on a $/MWh basis.

Table 4: HBPW Ten Least-Cost Expansion Plans (System Generation Cost Only)

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle available in 2016.	1,484,856	62.68
Fully optimized case. Purchasing 5 MW blocks of all coal and CFB units (except CCS units), and all generic units are available in 2016.	1,498,380	63.25
Purchasing 5 MW blocks of 2x300 MW CFB unit at Roger City in 2016.	1,499,619	63.30
Purchasing 30 MW block of 800 MW SCPC unit at Weadock in 2016.	1,500,649	63.35
Purchasing 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016.	1,502,967	63.44
Fully optimized case with 20 percent RPS requirements met with additional wind resources only.	1,505,064	63.53

[73] News Release | Consumers Energy; http://www.consumersenergy.com/News.aspx?id=2777&year=2010

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
No new units/blocks of units added. Everything is purchased from the market.	1,511,770	63.82
Buying 5 MW blocks of 70 MW net CFB unit to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,523,441	64.31
40 MW net CFB unit with CCS (whole plant) to be built by HBPW in 2016. JDY 3 to be retired in 2013.	1,578,367	66.63
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,591,727	67.19

Given that the cost difference between the least-cost and the most expensive is "not very significant,"[74] four of these alternative least-cost expansion plans were selected based on realistic circumstances and further evaluated for other advantages and disadvantages.

These four alternatives included:

Alternative 1: Purchasing 30 MW of the proposed 800 MW SCPC unit at the Consumers Energy Karn-Weadock facility.

Alternative 2: Owning the entire 70 MW CFB plant to be built by HBPW in 2016.

Alternative 3: Converting the Unit 9 CT into a 2x1 combined cycle unit in 2016.

Alternative 4: Owning 5 MW blocks (20 MW) of the 70 MW CFB plant co-fired with 30 percent biomass and coal to be built by HBPW.

The estimated total annual system costs and the cumulative present worth cost for each of these four alternatives selected for further evaluation, as well as their 20 year levelized cost, is depicted in Table 5.

[74] HBPW EGAA, p. 7-15

Table 5: Alternatives Selected for Further Evaluation (System Generation Cost Only)

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle available in 2016.	1,484,856	62.68
Purchasing 30 MW block of 800 MW SCPC unit at Karn-Weadock in 2016.	1,500,649	63.35
Purchasing 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016.	1,502,967	63.44
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,591,727	67.19

As indicated in Table 4 and Table 5, the least-cost expansion plan for HBPW was the conversion of the existing CT, CT9, into a 2x1 combined cycle plant. However, the model only selected a portion of the output as this plant will have a capacity of over 200 MW. As such, this plan requires additional power purchasers to take part in this expansion plan.[75]

The next least-cost expansion plan of the plans selected for further analysis was purchasing a 30 MW block of the 800 MW SCPC unit at the Consumers Energy Karn-Weadock facility. Consumers Energy was granted an air permit for this facility by the DNRE on December 29, 2009. The HBPW EGAA indicated that this option is contingent on HBPW being permitted to purchase 30 MW of the 800 MW plant.[76] As previously indicated, Consumers Energy has announced the postponement of this project.[77]

Using a 20 MW share of a self-built 70 MW CFB plant co-fired with 30 percent biomass and coal is the next least-cost expansion plan of the plans selected for further evaluation. HBPW EGAA indicated that this option is not contingent upon other external factors, reduces the carbon footprint of the system compared to the previous option, and includes other community benefits to the utility and its customers that are not available with other plans.[78]

Finally, the option of adding a new CFB plant and owning/maintaining all of the output from the plant for HBPW needs was the most costly alternative selected for further analysis given the assumptions for the costs reported in Table 5. With this option, HBPW would initially add more capacity than required, but would not need to add additional capacity until further out in the study period. Given the benefit of a fully owned and operated new generating resource over purchasing capacity from external resources, this option was selected for further evaluation.

[75] HBPW EGAA, p. 7-10
[76] HBPW EGAA, p. 7-14
[77] News Release | Consumers Energy; http://www.consumersenergy.com/News.aspx?id=2777&year=2010
78 HBPW EGAA, p. 7-14

Furthermore, the HBPW EGGA indicated that the addition of this plan would provide additional benefits for the community, which would offset some of the associated costs.[79]

In the figures presented in Table 4 and Table 5, a CO_2 allowance price was assumed, as previously described in this report. As part of the additional evaluation of the four alternatives selected for additional analysis, these alternatives were evaluated with no CO_2 allowance cost. Table 6 presents the results of this analysis.

Table 6: Alternative Analysis of No CO_2 Allowance Costs

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Purchasing 30 MW block of 800 MW SCPC unit at Weadock in 2016.	1,056,668	44.61
Purchasing 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016.	1,093,011	46.14
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle available in 2016.	1,094,288	46.19
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,105,908	46.68

These four alternatives were further analyzed to add in non-generating expenses (administrative, distribution, and depreciation) for the system for all the alternatives and deduce benefit credits (waste heat for city's snow melt system and potential expansion of waste heat use, funding for harbor dredging, and beneficial use of wastewater treatment solids) for applicable alternatives. Table 7 present the results of this analysis without CO_2 allowance costs.

Table 7: Alternative Analysis of Net System Cost after Adjusting for Benefit Credits and Without CO_2 Allowance Costs

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Purchasing 30 MW block of 800 MW SCPC unit at Weadock in 2016.	1,275,681	53.86

[79] HBPW EGAA, p. 7-15

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Purchasing 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016.	1,277,760	53.94
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,290,657	55.94
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle available in 2016.	1,313,301	55.44

The same analysis of non-generating costs and benefits credits for these four selected alternatives was performed with a CO_2 allowance cost. Table 8 presents the results of this analysis.

Table 8: Alternative Analysis of Net System Cost after Adjusting for Benefit Credits and With CO_2 Allowance Costs

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Purchasing 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016.	1,687,716	71.24
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle available in 2016.	1,703,869	71.93
Purchasing 30 MW block of 800 MW SCPC unit at Weadock in 2016.	1,719,662	72.59
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,776,476	74.98

In a supplement to the EGAA, three additional alternatives were evaluated and submitted to the docket on April 16, 2010. These additional alternatives included:

Additional Alternative 1: Evaluated building and owning a 65 MW (net) natural gas-fired combined cycle plant.

Additional Alternative 2: Evaluated supplying most of the energy requirements from wind and other renewable resources with small blocks of combustion turbines to maintain the system reserve margin. This alternative assumed the retirement of 103 MW of existing coal capacity over the 2012 to 2020 time frame with wind resources gradually increased from 50 MW in 2012 to 550 MW by 2022. A 20 percent capacity credit was given to wind in this analysis.

Additional Alternative 3: Evaluated supplying most of the energy and capacity requirements from wind and other renewable resources and phasing out existing coal units by 2020. This alternative assumed no new fossil fuel generating units were added in future years and all capacity requirements are fulfilled by new wind resource additions. This alternative assumed that around 1600 MW of nameplate capacity of wind resources were added to the portfolio to maintain the system reserve margin. A 20 percent capacity credit was given to wind in this analysis. In addition, it was assumed that surplus generation would be sold in the Midwest ISO energy market at prevailing market rates with revenue earned from the sales credited to the system cost. However, the cost for the significant transmission system upgrades that would likely be required as a result of the magnitude of the wind capacity was not taken into account as it was beyond the scope of the study.

These three (3) additional alternatives included the CO_2 allowance price assumptions as previously discussed. Table 9 below presents the results of the four alternatives selected for additional analysis, as previously discussed, and the results of these three additional alternatives. The costs presented in this table included additional non-generating system expenses, community benefit credits, and an assumed CO_2 allowance price, as previously discussed.

Table 9: Alternative Analysis of Initial Four Alternatives and Additional Alternatives (Net System Cost after Adjusting for Benefit Credits and With CO_2 Allowance Costs)

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Purchasing 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016.	1,687,716	71.24
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle available in 2016.	1,703,869	71.93
Purchasing 30 MW block of 800 MW SCPC unit at Karn-Weadock in 2016.	1,719,662	72.59
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,776,476	74.98
Additional Alternative 1: 65 MW net combined cycle unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in	1,782,290	75.24

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
2013.		
Additional Alternative 2: Providing most energy from wind resources and retiring all coal units by 2020.	2,464,164	104.02
Additional Alternative 3: Providing all future energy and capacity from wind and renewable energy resources and retiring all coal units by 2020.	3,318,277	140.07

Based on the assumptions made in this analysis, it appears that the Additional Alternative 1 of building a 65 MW combined cycle unit is cost competitive with the four alternatives originally chosen for further analysis.

The HBPW EGAA contended that several peaking, intermittent, intermediate, and baseload resource alternatives emerge to be available options to meet its projected resource capacity need starting in 2016.[80] One of these alternatives for new baseload capacity and energy includes the proposed HBPW 70 MW (net) CFB for which the HBPW BPW is currently seeking approval for a permit-to-install from the DNRE.

Public comments contend the HBPW EGAA disregards the availability of significantly under-utilized gas-fired combined cycle and gas turbine capacity in and around the state of Michigan that could be used to meet most, if not all, of the projected need. In addition, public contents also contend that building another baseload coal plant will contribute to a coal-dependent resource mix for decades.

Finally, public comments assert that given the current uncertainty associated with the economy, construction costs, potential federal greenhouse gas regulations and associated carbon control costs, make investment in a new coal-fired power plant a poor option until greater certainty emerges over the next several years. Instead, public comments suggest that a resource plan that postpones large capital expenditures for new coal-fired power plants and conversely provides flexibility for modification as circumstances change should be adopted.

[80] HBPW EGAA, p. 1-3

Alternative Coal Technologies

Various conventional coal-fired technologies were analyzed to meet the resource needs of HBPW. The technologies screened include circulating fluidized bed (CFB), supercritical pulverized coal (SCPC) and options of purchasing units of other potential coal-fired facilities. After the initial analysis of numerous coal-fired technologies, the options were narrowed down and alternatives were selected for further evaluation. The initial evaluations of all coal-fired technologies along with the cumulative present worth cost (CPCW) and levelized cost are displayed in Table 10.

Table 10: Ranking of Different Expansion Plans with CPWC Values

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)
Fully optimized case. Purchasing 5 MW blocks of all coal and CFB units (except CCS units), and all generic units available in 2016	1,498,380	63.25
Purchasing 5 MW blocks of 2 x 300 MW CFB unit at Rogers City in 2016	1,499,619	63.30
Purchasing 30 MW block of 800 MW SCPC unit at Weadock in 2016	1,500,649	63.35
Purchasing 5 MW Blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016	1,502,967	63.44
Purchasing 5 MW Block of 70 MW net CFB unit to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,523,441	64.31
40 MW net CFB unit with CCS (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,578,367	66.63
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,591,727	67.19

The initial evaluation presented numerous options that involved circulating fluidized bed technology possibilities. The CFB technology is characterized as providing reliable electric services at competitive efficiencies and greater fuel diversity in comparison to PC units.[81] HBPW evaluated the option of building a 40 MW (net) CFB facility with carbon capture and sequestration (CCS) and retiring the James De Young Unit 3 (JDY Unit 3) in 2013. This was not

[81] HBPW EGAA, p. 5-40

selected for further evaluation as HBPW contends this option is only viable if Department of Energy (DOE) funds can be obtained.[82] However, in a public comment submitted by Schlissel Technical Consulting, it is noted that it would be an extremely optimistic assumption that the DOE would pay for the entire cost of adding a CCS to a circulating fluidized bed plant. Schlissel Technical Consulting believes that if HBPW wanted to accurately test the economics of the proposed CFB plant, it should have looked at a range of scenarios in which support from the DOE increased from a level of no economic support, to a provision of a loan guarantee, to a scenario where some significant funding is supplied to the CCS equipment, but not 100% funding.[83]

Other CFB alternatives that were not selected for further evaluation involve the purchasing of capacity to meet HBPW resource needs. The option of purchasing shares of a proposed 2 x 300 MW CFB facility that may be built at Rogers City by Wolverine Electric Cooperative was not chosen as HBPW only wants to purchase 20 MW of the 600 MW plant. According to HBPW, securing a small ownership share may not be possible.[84] Along with this, the Michigan Department of Natural Resources and Environment (DNRE) recently denied Wolverine's air quality permit-to-install application for the proposed plant. This decreases the chance of construction of the facility and partial ownership by HBPW.

Additional alternatives that feature the purchasing of capacity, but were not chosen for further evaluation, include a fully optimized case that consisted of purchasing capacity from different resources in 5 MW increments in all years of the study period (2010-2029).[85] The capacity evaluated was coal and CFB units (except CCS units) and all generic units available in 2016.[86] While this plan is competitively priced, acquiring small capacity blocks of generating resources each year makes implementation of this option difficult.[87] Generation plants are constructed once a decision to build is made; they are not built in fractional units. HBPW presented another scenario of purchasing 5 MW blocks of a 70 MW net CFB unit to be built in 2016 and retiring the JDY Unit 3 in 2013. Once again, this option was modeled based on an ideal world scenario. In the real world, building fractional units of a plant is not a viable option.

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[82] HBPW EGAA, p. 7-15
[83] Comments from Schlissel Technical Consulting, http://efile.mpsc.state.mi.us/efile/docs/16077/0034.pdf, p. 47
[84] HBPW EGAA, p. 7-14
[85] HBPW EGAA, p. 7-1
[86] HBPW EGAA, p. 7-11
[87] HBPW EGAA, p. 7-14

The options that were selected for further evaluation are presented below in Table 11.

Table 11: Ranking of Selected Expansion Plans and Additional Plans Based on Net System Cost after Adjusting for Benefit Credits Including CO_2 Allowance Costs

Plan Description	CPWC Value-2010 Dollars (000s)	Levelized Cost ($/MWh)
Purchasing 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016	1,687,716	71.24
Purchasing 30 MW block of 800 MW SCPC unit at Weadock in 2016	1,719,662	72.59
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013	1,776,476	74.98

The supercritical pulverized coal technology selected for further evaluation is the purchase of a proposed 30 MW block of an 800 MW SCPC unit at Consumers Energy's Karn-Weadock plant. According to HBPW's Supply Plan, SCPC units offer a commonly used and proven technology with a high reliability level.[88] However, after further evaluation, HBPW found this alternative to contain no community benefits such as providing a waste heat source for the City of HBPW's snow melt system.[89] Additionally, HBPW evaluated this scenario assuming impacts of potential CO_2 legislation and determined that this option is the most carbon intensive plan, as there are no carbon sequestration measures.[90] As previously indicated in this Staff Report, Consumers Energy has announced postponement of this project until further notice.

HBPW further analyzed the purchase of 5 MW blocks of a 70 MW net CFB unit using 30% biomass to be built by HBPW and determined this alternative would include the community benefits not found in the purchase of 30 MW from Consumers Energy. This choice would also help HBPW exceed the minimum RPS requirements specified in Michigan PA 295.[91] HBPW contends this option is not as carbon intensive as the purchase of 30 MW from Consumer Energy. However, no partnering utilities were identified as part of this scenario. Additionally, the construction of fractional units of capacity is not a practical alternative in adding generation.

Finally, after further evaluation, HBPW recommended continuing to pursue the construction of a 70 MW net CFB unit. This choice would require that the existing coal-fired JDY Unit 3 plant be

[88] HBPW EGAA, p. 5-35
[89] HBPW EGAA, p. 7-18
[90] HBPW EGAA, p. 7-21
[91] HBPW EGAA, p. 7-18

retired at the end of 2013 and the new 70 MW net CFB unit built at that site.[92] Again HBPW contends this option provides community benefits for the city's snow melt system.[93] Even though this is the most expensive plan, this option has the greatest level of control for HBPW. The other alternatives are heavily dependent upon participation of others that may not materialize. HBPW suggests that, due to the community benefits, independence, and the flexibility of fuels for the CFB that this remains a viable option.

Energy Efficiency and Demand-Side Strategies

HBPW acknowledges that a "detailed specific DSM and EE study for the City of Holland was beyond the scope of this study."[94] Although a detailed specific study for energy efficiency and demand side alternatives was not completed, HBPW did include reductions to its load forecast based upon assumptions regarding energy efficiency and demand side strategies. For the near term, HBPW adjusted its sales forecast downward to reflect the expectation that it will meet the energy savings targets set forth by 2008 PA 295 through 2015.

Table 12: PA 295 Energy Efficiency Savings Assumptions

Timeframe	Energy Efficiency Assumption	Basis for Assumption
2009	0.3% Energy savings	2008 PA 295 requirements[95]
2010	0.5% Energy savings	2008 PA 295 requirements
2011	0.75% Energy savings	2008 PA 295 requirements
2012 – 2015	1% Annual energy savings	2008 PA 295 requirements

HBPW's Energy Optimization Plan that was submitted to the Commission in April 2009 projected savings of up to 9,169 MWh[96] in the year 2012.

Beyond 2015, HBPW used the Electric Power Research Institute (EPRI) Assessment of Achievable Potential and Demand Response Programs in the U.S. for 2010-2030[97] to project future savings in the HBPW territory. Specifically, for 2016 through 2030 HBPW based the expected amount of energy efficiency savings upon the amount indicated as the Realistic Achievable Potential (RAP) in the EPRI report.

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[92] HBPW EGAA, p. 7-4
[93] HBPW EGAA, p. 7-16
[94] HBPW EGAA, p. 3-7
[95] 2008 PA 295, http://www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf.
[96] HBPW EGAA, p. 3-6.
[97] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010 – 2030). Electric Power Research Institute (EPRI), http://www.edisonfoundation.net/IEE/reports/EPRI_SummaryAssessmentAchievableEEPotential0109.pdf

Table 13: Energy Potential Estimates as Percentage of Energy Requirements

Year	2010	2020	2030
RAP	0.5%	4.8%	8.2%

The energy savings resulting from energy efficiency and demand side strategies assumed in HBPW's supply plan reaches a total of 8.2% savings in the year 2030 using the EPRI RAP assumptions.

HBPW calculated projected reductions to peak demand for 2010 to 2015 by assuming the energy savings specified in 2008 PA 295 and using an assumed load factor equal to its load factor for 2009. Reductions to peak demand for 2016 through 2030 "incorporate EPRI's RAP [realistic achievable potential] DSM savings forecast for peak demand."[98]

Table 14: HBPW's Assumed Reductions to Peak Demand

Year	Peak Demand Before DSM Savings[99]	Peak Demand Adjusting for RAP DSM Savings[100]	Calculated Peak Reduction
2015	250 MW	230 MW	8.0 %
2030	308 MW	287 MW	6.8 %

Public comments received take exception to the statement previously mentioned concerning HBPW's failure to specifically study DSM and EE for the City of Holland. Comments reflect that the "citizens of Holland have never settled for minimum or average performance on any worthwhile goal" and the aforementioned statement was "the single most disappointing sentence in the EGAA."[101] Another comment submitted contends that HBPW used a dated EPRI study when justifying that only a 0.5% energy efficiency improvement a year can be made after 2015. The commenter explains that the current government administration's implementation of energy efficiency actions were put in place after the EPRI report was written. Due to the current initiatives, energy efficiency savings are underestimated.[102]

Comments contend that HBPW'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 and demand side management 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.

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[98] HBPW EGAA, p. 3-11.
[99] Document 0028, response to Sierra Club Question #12
[100] Document 0053, response to Staff Question #2
[101] Comments from Dr. Donald Triezenberg, http://efile.mpsc.state.mi.us/efile/docs/16077/0029.pdf, p. 3
[102] Comments from Frank A. Zaski, http://efile.mpsc.state.mi.us/efile/docs/16077/0012.pdf, p. 4-5

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."[103]

Staff requested HBPW to describe potential changes to its overall supply plan, should the MCAC policy recommendation of 2% per year energy optimization savings come to fruition. HBPW states that "it is somewhat speculative to assess a potential impact from the Michigan Climate Action Council goal of 2 percent energy reduction per year until such goals are legislated into mandatory rules because it is unknown what the specific details of such legislation might require. The details of such potential legislation could potentially include a wide variation in requirements."[104] HBPW also made the point that future building codes will play a role in future savings to be gained from energy efficiency. "It is important to note that the success of many energy efficiency measures will be dependent upon legislative actions taken to require certain efficiency levels in new construction building codes."[105]

In the past, Staff viewed energy efficiency potential study results for the state of Wisconsin as providing a reasonable proxy for the state of Michigan. With little recent experience or data to draw from, and no Michigan-based energy efficiency potential study results, the states' Midwest proximity as well as their similar climate and electric use characteristics lend support for this logic.

In fact, a 2005 Energy Center of Wisconsin (ECW) energy efficiency study of Wisconsin was used by Staff in the preparation of the 21st CEP, as a first step to modeling the energy efficiency potential in Michigan. With this in mind, Staff reviewed an August 2009 report of an energy efficiency potential study prepared by the ECW for the Wisconsin Public Service Commission[106] for an indication of the energy efficiency potential Michigan might experience.[107]

There are distinctions between Wisconsin and Michigan in terms of their recent experience with Energy Efficiency programming. Energy efficiency programs in Wisconsin began with a pilot in 2000, followed by the official start-up of state-wide programs in 2001. The recent 2009 Wisconsin energy potential study was undertaken to determine what savings could be achieved with an aggressive program, beyond a business-as-usual approach. Examples given for aggressive programming included capturing neglected opportunities through large scale retrofits, deployment of advanced rate designs to reduce peak electric demand and expanding behavior-based approaches to motivating energy efficiency savings. According to the report, the Base Case scenario focused on the economic benefits from saving energy and the environmental benefits of avoided carbon emissions while the assumptions under the aggressive scenario focused additionally on higher avoided costs, a less-restrictive cost-effectiveness screen and a

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[103] 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.
[104] Document 0053, response to Staff question #1
[105] Document 0053, response to Staff question #3
[106] Energy Center of Wisconsin's, *Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin for the Years 2012 and 2018*, August 2009, http://psc.wi.gov/reports/documents/WIPotentialFinal.pdf
[107] For the 21st CEP EE potential study, the Wisconsin model was updated with a limited number of macro-scale modifications in order to account for differences in the scale of Michigan markets and variation in weather patterns. No such updates were made to compare the 2008 Wisconsin potential study.

lower discount rate. The energy and peak demand savings estimates for the Base Case and Aggressive Case scenario are shown in the table below and ranged from a 1.6% annual savings potential for the Base Case, to 1.9% annual savings for the Aggressive Case.

Table 15: 2009 Wisconsin Energy Efficiency Potential Study Results

Base Case	Energy Savings (GWh)	Peak Demand Savings (MW)
Annually by 2012	1,200 GWh or 1.6% of sales	250 MW or 1.6% of peak demand
Cumulative by 2018	11,000 GWh or 13% of sales	2300 MW or 13% of peak demand

Aggressive Case	Energy Savings (GWh)	Peak Demand Savings (MW)
Annually by 2012	1,400 GWh or 1.9% of sales	300 MW or 1.9% of peak demand
Cumulative by 2018	13,000 GWh or 16% of sales	2700 MW or 16% of peak demand

Despite the infancy of energy efficiency programming efforts in Michigan, it is reasonable to consider Wisconsin's Base Case energy efficiency potential study results as a Michigan proxy in this case, due to the considerable opportunities in capturing 'low hanging fruit' within easy reach. Other nation-wide potential studies also support higher electric energy efficiency potential savings numbers. A recent American Council for an Energy Efficient Economy (ACEEE) review of 20 state, regional and national electricity efficiency potential studies identified average achievable electricity saving potential of 1.5%, with Illinois and Ohio each averaging 2.0%.[108]

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.[109] The following table shows a comparison of HBPW's assumed reductions to peak demand as compared to potential studies that have been published.

[108] Eldridge, M, R. N. Elliot, and Max Neubauer. 2008. *State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned.* American Council for an Energy-Efficient Economy.

[109] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010 – 2030). Electric Power Research Institute (EPRI), http://www.edisonfoundation.net/IEE/reports/EPRI_SummaryAssessmentAchievableEEPotential0109.pdf

Table 16: Peak Demand Reduction Potential (% of Peak Demand)

Year	2015	2018	2030
HBPW's Assumed Reductions to Peak Demand	8.0%		6.8%
EPRI's RAP Demand Reduction			14%
EPRI's MAP Demand Reduction			19.5%
Wisconsin Base Case Demand Reduction		13%	
Wisconsin Aggressive Case Demand Reduction		16%	

Considering the MCAC goal of 2% incremental energy efficiency per year starting in 2015, along with the peak demand potential cited in the above studies, the amount of peak demand reduction assumed in 2030 within HBPW's supply plan appears conservative. While HBPW estimated the impact to peak load from savings due to energy efficiency, HBPW did not specifically discuss any direct load control programs, demand response or any other demand side options to reduce the peak demand beyond energy efficiency. Given HBPW's existing and projected customer base, HBPW could benefit from further investigation of demand side options that may be available to reduce future peak demand. 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, and should be considered in the resource mix beyond the minimum requirements set forth in 2008 PA 295.

Renewable Energy

As required in the EGAA process, HBPW provides a review of available renewable energy (RE) conversion technologies and their potential for meeting energy needs of their system. However, it appears that only a cursory review of available renewable energy resources has been completed, to date. Based on the information provided by HBPW, Staff cannot conclude that HBPW's analysis of renewable energy technologies and available resources is adequate for resource planning purposes. On the contrary, it appears that HBPW's RE analysis hinges almost exclusively on highly selective, incomplete information provided by Black & Veatch. Apparently, additional details exist, but Black & Veatch, HBPW, or both parties consider that data to be confidential.[110] Staff believes HBPW's EGAA underestimates the potential for

[110] Document 0037, p. 1, response to Staff question 1.

renewable energy to play an increasingly important role in meeting HBPW customers' near-term and long-term future energy needs, at costs substantially less than, or at least fully competitive, with its proposed new, primarily coal-fueled option.

Review of Specific Renewable Energy Resources and Conversion Technologies

Biomass and Landfill Gas

HBPW's EGAA provides basic characterizations of biomass direct combustion, biomass co-firing with coal, and landfill gas. The Study also touches on biomass gasification.[111] HBPW provides this summary:

> Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating value of the fuels, biomass plants are typically less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis, if sited over 75 miles from the fuel source, because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.[112]

HBPW suggests that co-firing biomass with coal is "one of the most economical methods to burn biomass…" HBPW's plans for its new primarily coal-burning facility do include co-firing with woody biomass and with biosolids that are a waste byproduct of its operation of a wastewater treatment plant.[113]

Table 17 shows the assumptions HBPW used about biomass combustion technology.

Table 17: Biomass Combustion Assumptions

Typical Duty Cycle	**Baseload**
Net Plant Capacity (MW)	35-75
Net Plant Heat Rate (HHV, Btu/kWh)	14,500
Capacity Factor (%)	80-90
Economics ($2009)	
Total Project Cost ($/kW)	4,500-5100
Fixed O & M Cost ($/kW-yr)	100

111 HBPW EGAA p.5-6 – 5-14.
112 HBPW EGAA, p. 5-6.
113 HBPW EGAA, p. 7-16. 7-18.

Typical Duty Cycle	Baseload
Variable O & M ($/MWh)	3
Levelized Cost[(114)]	
Municipal	100-150
PPA[(115)]	120-150

Table 18 presents HBPW's assumptions for biomass co-firing technology.

Table 18: Biomass Co-Firing Assumptions

Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35
Net Plant Heat Rate (HHV, Btu/kWh)	Increase .05-1.5%
Capacity Factor (%)	Unchanged
Economics ($2009)	
Total Project Cost ($/kW)	300-500
Variable O & M Cost ($/MWh)	0-3
Fuel Cost ($/MBtu)	3.00
Levelized Cost(116**) ($/MWh)**	
Municipal	40-50
PPA[(117)]	30-40

HBPW indicates landfill gas (LFG) facilities are typically smaller than 10 MW. It reports:

> LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation.

HBPW also notes, installation of such a facility relies profoundly on the characteristics of the chosen landfill. HBPW already has contracts with independent suppliers, to procure renewable energy generated using LFG.[118] Table 19 presents HBPW's assumptions regarding Landfill Gas facilities.

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[114]The low ends of the levelized costs are based on a 90% capacity factor and a capital cost of $4,500/kW. The high ends of the levelized costs are based on a 70% capacity factor and a capital cost of $5,100kW. Fuel cost is assumed to be $3.00/MBtu.

[115] Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

[116] The low end of the levelized cost is based on a capital cost of $300/kW and O&M cost of $0/MWh. The high end is based on capital cost of $500 KW and O&M cost of $3/MWh

[117] Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

[118] HBPW EGAA, Sections 2.3.2 and 2.3.3, p. 2-4 – 2-5.

Table 19: LFG Assumptions

Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.2-15
Net Plant Heat Rate (HHV, Btu/kWh)	11,500
Capacity Factor (%)	70-90
Economics ($2009)	
Total Project Cost ($/kW)	1,700-2,800
Fixed O&M ($/kW-year)	27
Variable O&M ($/MWh)	15
Levelized Cost(119**) ($/MWh)**	
Municipal	70-85
PPA[(120)]	60-90

Staff has three major criticisms of HBPW's assessment of biomass and landfill gas resources: (1) the general lack of information about the local area's available biomass resources and overly narrow view of what might constitute available resources; (2) the focus on co-firing in the proposed coal-burning unit, which appears most likely to result in the creation of a large percentage of waste heat; and, (3) the lack of efforts to identify possible in-service-territory or nearby candidates to be hosts for biomass-fired CHP units.

In answer to Staff's questions, HBPW indicates a survey of selected biomass resources is underway now, "for a 100-mile radius around the James De Young plant."[121] The Utility further indicates it has conducted "a survey of nearby landfills," but makes no indication of the findings of that survey, except to say, "Holland's desire would be to diversify its renewable energy sources rather than relying on one technology."[122]

Staff applauds HBPW for exploring the options of co-firing biomass fuel and its own wastewater treatment plant biosolids in the proposed CFB coal-burning plant. Staff is also encouraged to learn that the area biomass resource assessment is now being completed. However, Staff has two major concerns about these issues:

First, one result of co-firing is likely to be low efficiency of converting biomass fuel to useful energy. Even with the modest amount of waste heat utilization at HBPW's facility, it is Staff's understanding that a large portion of waste heat will be created. Michigan has significant amounts of otherwise-low-value biomass that might be cost-effectively converted to useful

[119] The low end of the levelized cost is based on a net plant capacity of 15 MW, a 90% capacity factor, and a capital cost of $1,700/kW. The high end is based on a net plant capacity of 0.2 MW, a 70% capacity factor, and a $2,800/kW capital cost.
[120] Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.
[121] Document 0037, p. 12, answer to Staff question 41.
[122] Document 0037, p. 12, answer to Staff question 42.

energy. But, such materials ought not to be wasted, and they often have many present and future competing, often higher-value uses.[123]

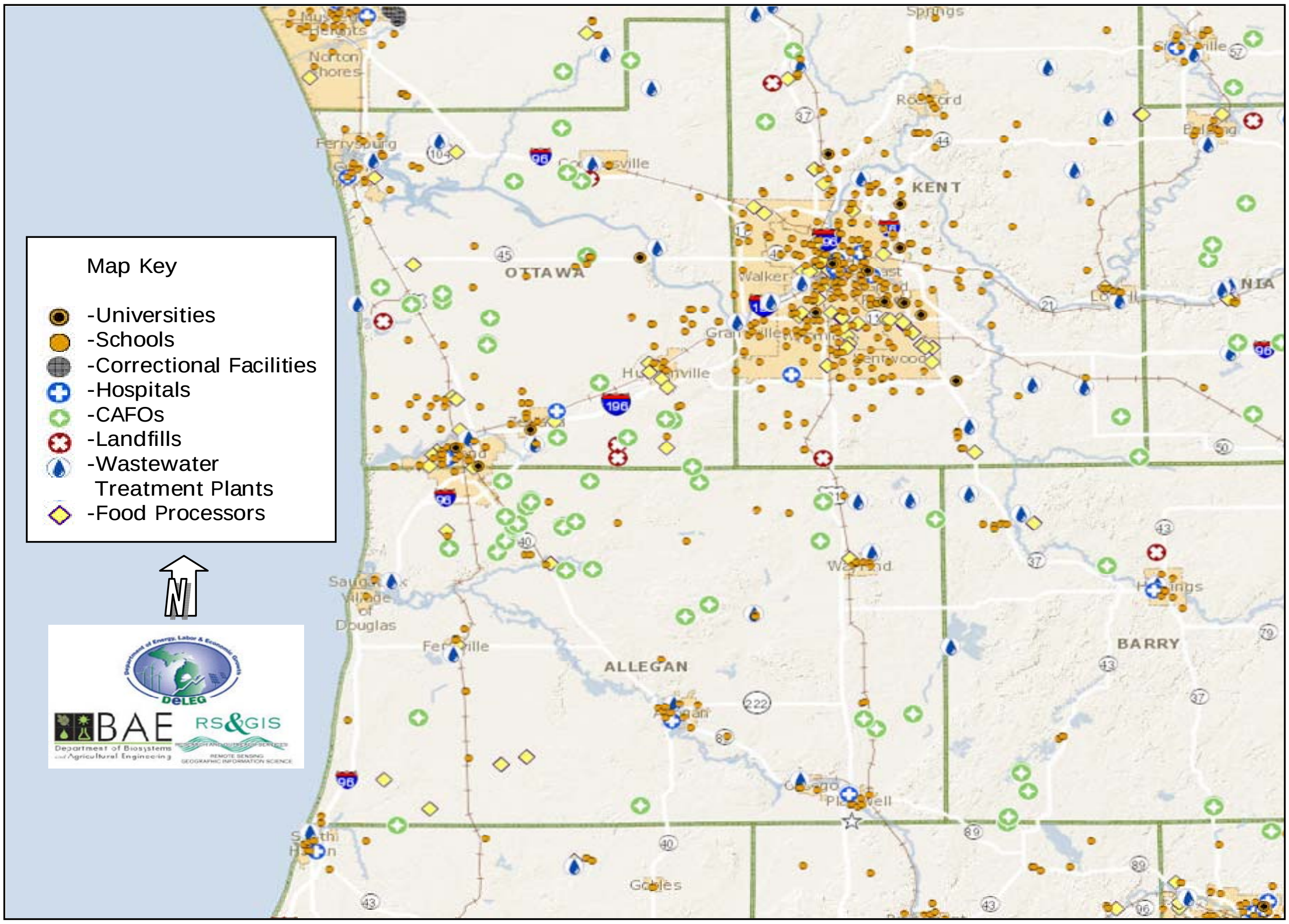
Staff believes the option of utilizing the same quantities of fuel in a larger number of small, distributed generators will readily allow utilization of much larger quantities of the waste heat. It is not uncommon for a carefully planned biomass combined heat and power (CHP) facility to convert upwards of 80% of all its fuel energy to various forms of useful energy. That is roughly double the efficiency of a central station plant with minimal waste heat utilization. HBPW's focus on efficiency in its EGAA report is apparently solely on the heat rate (that is, how many Btus of fuel are necessary, on average, to produce each kWh). This is a different metric of efficiency, and Staff believes a less important one, compared to understanding the efficiency of converting fuel energy into any kind of useful energy, often using co-generation or tri-generation to achieve much higher efficiencies.

Second, HBPW's ongoing biomass resource assessment is limited to "[w]hole tree chip, sawmill chips and clean manufacturing wood waste."[124]

As depicted in Figure 8, many additional sources of biomass fuel remain to be explored.

[123] See Michigan Biomass Energy Program, June 2006, *Clean Energy from Wood Residues in Michigan*, p. 15, 25-26;http://www.michigan.gov/documents/wood_energy_in_michigan--final1_169999_7.pdf.
[124] Document 0053, p. 8, answer to Staff question 21e.

Figure 8: Possible Producers and Users of Biomass Energy in HBPW Area



Source: Michigan Waste Biomass Energy Inventory to Support Renewable Energy Development. (Beta Version, September 2009). Interactive mapping tool available at: http://mibiomass.rsgis.msu.edu/.

As shown in Figure 8, there do appear to be many possible sources of potential biomass fuel in the HBPW area and a number of plausible host sites for small-scale biomass generation facilities. Staff recognizes that this map and the inventory it is based upon are only high level starting points for locating resources and sites for biomass conversion facilities.[125] Nevertheless, Staff believes due diligence requires a more thorough assessment of biomass opportunities, prior to locking in a decision to build a baseload power plant.

[125] For information about the process of developing a more detailed inventory of promising host facilities, see fn 157.

Wind Energy

HBPW correctly observes that Michigan is not considered a national leader in wind energy installations.[126] HBPW summarizes the cost and performance characteristics of wind energy:

> After several years of high price escalation, capital costs for new onshore wind projects have stabilized. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for newly installed wind projects in the United States has increased from approximately 24 percent before 1999 to around 32 percent currently.[127]

Table 20 presents HBPW's assumptions regarding wind energy.

Table 20: Wind Energy Assumptions

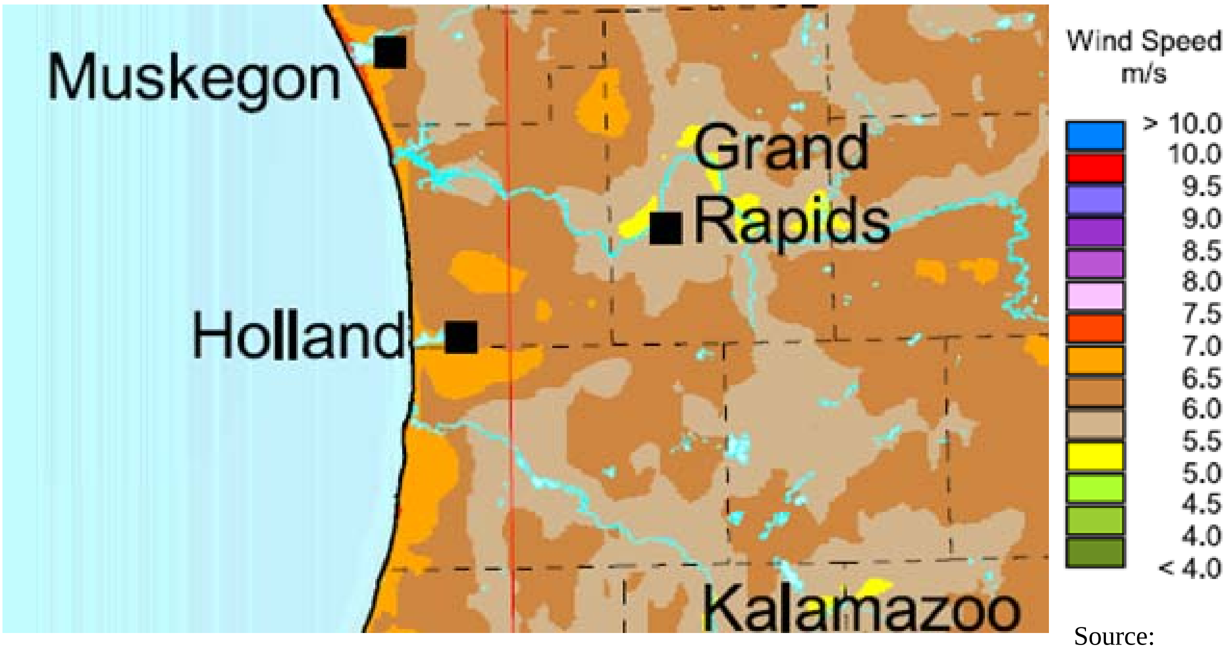
	Onshore	**Offshore**
Typical Duty Cycle	As available	As available
Net Plant Capacity (MW)	2.5	2.5
Capacity Factor (%)	20-35[128]	30-40
Economics ($2009)		
Total Project Cost ($/kW)	2,400-3,000	5,000-6,000
Fixed O&M ($/kW-year)	50	60
Variable O&M ($/MWh)	(included w/fixed O&M)	(included w/fixed O&M)
Levelized Cost[129] ($/MWh)		
Municipal	90-110	140-170
PPA[130]	100-150	160-260

Staff's major concern about HBPW's analysis of wind energy is what appears to be an incomplete report regarding area wind resources and an incomplete analysis of wind electricity production options. HBPW also appears to be overly concerned about system integration costs that might be associated with the introduction of growing quantities of RE from variable output generation options, such as wind and solar. As mentioned earlier, Staff believes HBPW used a static price for wind electricity, rather than considering technological and cost digression over time.

[126] HBPW EGAA, p. 5-15.
[127] HBPW EGAA, p. 5-16.
[128] Representative of existing projects in Michigan
[129] The low end of the levelized cost is based on net plant capacity of 200 MW, capacity factor of 35%, and capital cost of $2,400/kW. The high end of the levelized cost is based on net plant capacity of 50 MW, capacity factor of 28%, and capital cost of $3,000/kW.
[130] Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy

Figure 9 shows annual average wind resource estimates for the HBPW area. This is an excerpt from a Michigan map made available by the National Renewable Energy Laboratory in February 2010. According to a fact sheet from the American Wind Energy Association (AWEA), *Ten Steps to Developing a Wind Farm*, the minimum average annual wind speed for a commercially viable wind farm should be at least 6 meters per second (m/s).[131]

Figure 9: 80-Meter Wind Resource Map for HBPW Area



Source: Wind resource estimates developed by AWS Truewind, LLC, for National Renewable Energy Laboratory. See http://www.windpoweringamerica.gov/wind_maps.asp.

As shown in Figure 9, there are significant areas near HBPW with wind speeds equal to or greater than this minimum criterion. In fact, the western portion of Allegan County is one of four areas in Michigan found to have the highest wind energy potential by the State's Wind Energy Resource Zone Board.[132] The Board's recommendation led to this area being designated by the Commission as a Wind Energy Resource Zone.[133]

HBPW does indicate the Utility "continues to evaluate several wind projects as noted on page 2-5" of its EGAA document.[134] It further explains, "Holland has nondisclosure agreements with various entities involved with the exploration of potential development of wind resources."[135]

Solar Energy

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[131] See http://www.awea.org/pubs/factsheets/Ten_Steps.pdf.
[132] Document 0037, p. 10, response to Staff question 37.
[133] See http://www.dleg.state.mi.us/mpsc/renewables/windboard/werzb_final_report.pdf and http://efile.mpsc.state.mi.us/efile/docs/15899/0089.pdf.
[134] Document 0053, p. 6, response to Staff question 15.
[135] Document 0037, p. 11, response to Staff question 37.

HBPW explains that solar photovoltaic (PV) technology "has achieved considerable consumer acceptance over the last few years… [and] PV module production has experienced significant growth… "[136] HBPW reviewed both PV and solar thermal technologies that are sometimes used for the production of electricity. (These "solar thermal" technologies are different from solar technologies designed to generate heat, for use in water heating, space heating and cooling, and similar applications.)

HBPW concludes that due to high costs associated with solar thermal plants, this type of generation will not be competitive within the state of Michigan. Table 21 presents HBPW's assumptions regarding solar parabolic trough systems, which is representative of solar thermal technologies.[137]

Table 21: Solar Parabolic Trough Assumptions

Typical Duty Cycle	**Peaking-Intermediate**
Net Plant Capacity (MW)	100
Integrated Storage	3 hours
Capacity Factor (%)	14
Economics ($2009)	
Total Project Cost ($/kW)	7,000-9,000
Total O&M ($/MWh)	67
Levelized Cost[138] ($/MWh)	
Municipal	550-700
PPA[139]	300-400

Table 22 presents HBPW's assumptions regarding PV.

Table 22: Solar PV Assumptions

	Crystalline, Single Axis	**Thin Films**
Typical Duty Cycle	As available, Peaking	As available, Peaking
Net Plant Capacity (MW)	20	20
Capacity Factor (%)	15	14

[136] HBPW EGAA, p. 5-19.
[137] Parabolic trough cost estimates have a higher degree of uncertainty for near-term applications
[138] The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high ends of the levelized cost are based on the lower capacity factors and higher capital and O&M costs.
[139] Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy

	Crystalline, Single Axis	Thin Films
Economics ($2009)		
Total Project Cost ($/kW)	6,400-7,000	3,600-4,000
Total O & M ($/MWh)	65	55
Levelized Cost[140] ($/MWh)		
Municipal	450-550	300-350
PPA[141]	250-300	180-220

With respect to HBPW's analysis of solar energy, staff has these concerns: (1) incomplete or overly pessimistic analysis of solar energy's ability to contribute to peak power production and peak load reductions; and (2), failure to model more options for PV installations of various sizes and smaller-scale solar thermal conversion technologies. Like its analysis of other RE options, the solar analysis suffers from the static, rather than dynamic, estimate of PV system prices.

Solar PV and thermal systems are likely to provide output with high peak load coincidence. Solar radiation delivers most of its energy during the highest cost hours and days of each month, and during the highest costs days and months of each year.[142] In fact, PV production in Michigan is fairly well concentrated during hours when the market price for electricity is well above the annual average. A summer peaking electric provider generally has the highest demands on the same days that solar produces at its peak potential. Peak usage in Michigan is generally driven by heating loads in the winter and increasingly by air conditioning load in the summer.

Effective load carrying capability (ELCC) is the calculated capacity credit for a given electric generating system. It is calculated based on long-standing principles in the electric utility industry, based on application of a consistent methodology intended to accurately reflect a wide variety of risk and performance variables.[143] Research shows that the coincidence between solar production and peak load results in ELCC percentages from 32% to 65%, depending on the location, quantity of PV employed, and mounting systems used.[144] Due to the reasonably high

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[140] The lower levelized costs are based on the low ends of the total project costs, and the high levelized costs are based on the high ends of the total project costs.

[141] Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy

[142] In a climate like ours, both the coldest winter days and hottest summer days tend to be sunniest. PV production will be somewhat higher when the PV system itself is colder. PV performance actually degrades a bit during hot weather. However, during the summer months there are many more hours of sunlight available each day and the angle of the sun is likely to be more directly perpendicular to PV panels, which both tend to lead to high daily output during the summer.

[143] See Contreras, J.L., L. Frantzis, S. Blazewicz, D. Pinault, and H. Sawyer, February 2008, *Photovoltaics Value Analysis*, National Renewable Energy Laboratory, NREL/SR-581-42303; http://www.nrel.gov/docs/fy08osti/42303.pdf. See also Michigan Wind Working Group Subcommittee on Capacity Credits, Michigan Renewable Energy Program, March 2005, *Proposal for Capacity Credits for Variable Output Electric Power Generators in Michigan;* http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/othergen/draftcapacitycreditsmar05.pdf.

[144] Perez, Richard, et al., *Update: Effective Load Carrying Capability of Photovoltaics in the United States.* http://www.asrc.cestm.albany.edu/perez/publications/Utility%20Peak%20Shaving%20and%20Capacity%20Credit/

correlation between the peak hours of PV production and Michigan electricity peak demand times, solar electricity production can help to serve peak loads. Because daily and monthly PV production matches peak demands fairly well, PV tends to offset high-priced production or purchases.[145]

HBPW EGAA presents cost and performance estimates for 20kW solar PV installations, using two different kinds of photovoltaic materials (crystalline and amorphous). It should be noted that the text of the EGAA indicates, on page 5-21, that Table 5-7 presents data for "a 20-MW utility-scale PV energy center." Staff is uncertain whether kW or MW is appropriate for this data set, but the idea of a "utility-scale PV energy center" is certainly much more likely associated with a 20MW facility. This begs the question, then, why the estimated costs for such a facility are so high. Table 5-7 shows levelized costs ranging from $180 to $550 per MWh, even after including the 30% federal financial support and 5-year accelerated depreciation. Staff agrees that the low end of these price estimates might be realistic today for a utility-scale installation in Michigan. For example, Detroit Edison recently entered into a contract with a developer that agrees to construct up to 3 MW of solar PV generating facilities at a maximum cost per kW of $6,500, and Consumers Energy's Experimental Advanced Renewable Program is attracting development of PV for commercial customers (>20kW, up to 150kW), with a 12-year contract rate of $0.375/kWh.[146] Therefore, Staff sees no evidence in the HBPW EGAA that PV systems in future years will have increasing performance and declining cost. Such improvements are expected by a large variety of industry observers, including the U.S. Department of Energy, and should be included in any long-range utility system modeling.[147]

Hydroelectric and Hydrokinetic Energy

Michigan has approximately 209 MW of developed small hydropower resources with an estimated 133 MW of additional potential capacity.[148] HBPW EGAA asserts that hydroelectric generation is regarded as mature technology that is unlikely to advance measurably.[149] Table 23 presents HBPW's assumptions regarding hydroelectric power.

Papers%20on%20PV%20Load%20Matching%20and%20Economic%20Evaluation/update%20effective%20load%20carrying%20capability%20of%20PV-06.pdf.

[145] Lovins, et al, 2002, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, Section 2.2.8, Matching Loadshapes.

[146] See Detroit Edison – Nova Consultants contract, p. 13, http://efile.mpsc.state.mi.us/efile/docs/15806/0195.pdf. For EARP information see http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MI24F&re=1&ee=0.

[147] See U.S. Department of Energy, Solar Energy Technologies Program, *Solar Vision Study*, 2010; http://www1.eere.energy.gov/solar/vision_study.html.

[148] Idaho national Engineering and Environmental Laboratory, *Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants*, January 2006; http://hydropower.inel.gov/resourceassessment/pdfs/main_report_appendix_a_final.pdf.

[149] HBPW EGAA p. 5-24

Table 23: Hydroelectric Assumptions

	New Hydro Installations
Typical Duty Cycle	Varies with Resource
Net Plant Capacity (MW)	25-50
Capacity Factor (%)	50
Economics ($2006)	
Total Project Cost ($/kW)	4,000-5,000
Fixed O&M ($/MWh)	50
Variable O&M ($/MWh)	(included in Fixed O&M)
Levelized Cost[150] ($/MWh)	
Municipal	90-110
PPA[151]	115-140

Staff's concerns with HBPW's analysis of hydroelectric options are: (1) the lack of information about local resources that might be developable; and (2) the incomplete analysis of new, hydrokinetic options. Hydrokinetic options are those that utilize the kinetic energy inherent in moving water, without reliance on any impoundment behind a dam. Examples include devices that capture useful energy from water currents (in open rivers and streams, or in water pipes), and wave and tidal power.

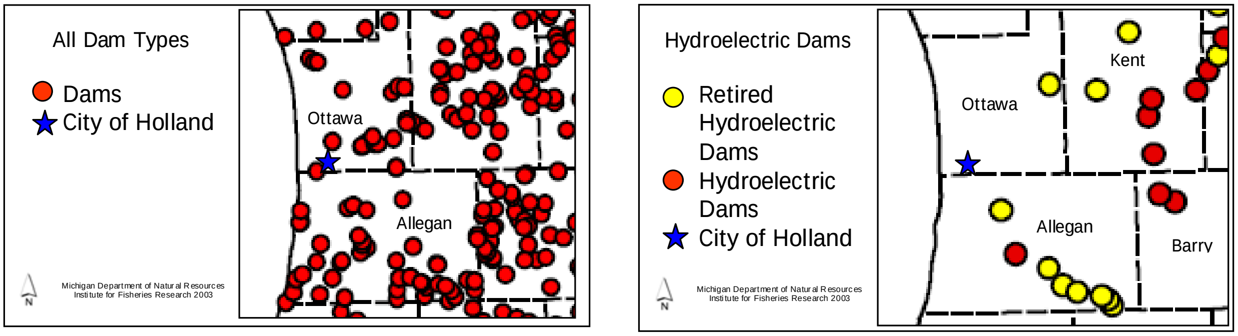
Staff does not find any particular fault with the technical information HBPW provides regarding hydroelectric and hydrokinetic options. In addition, Staff recognizes that at this time: (a) most available hydrokinetic technologies are nascent and pre-commercial; (b) many challenges are associated with efforts to redevelop previously abandoned hydroelectric facilities; and (c) perhaps insurmountable challenges are associated with the development of any new dams. However, the Utility reports it has not "conducted, or obtained from any other entity, any surveys, or analyses of the potential for hydroelectricity or hydrokinetic electricity production…in or near Holland's service territory."[152] According to the most recently published inventory, Michigan has a total of approximately 209 MW of developed small hydropower resources with an estimated 133 MW of additional potential capacity.[153] This data comes from a study of existing dams, and does not include any production that might come from either new dams or hydro-kinetic energy systems that do not require any water impoundment behind a dam,

[150] The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high end of the levelized cost is based on the lower capacity factors and the higher capital O&M costs.
[151] Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy
[152] Document 0053, p. 5, response to Staff question 13.
[153] Idaho National Engineering and Environmental Laboratory. (January 2006). *Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants*. The most commonly accepted classifications for hydro generation projects include: (1) micro-hydro, which generate less than 100 kW; (2) mini-hydro, between 100 kW and 1.5 MW; and small-hydro ranging from 1.5 to 30 MW.

such as current-flow or wave-energy devices. As shown in Figure 10, though, there do appear to be several possible opportunities for additional hydroelectric capacity near Holland.

In addition, Staff notes that both Consumers Energy[154] and Detroit Edison[155] have recently entered into contracts with small hydroelectric producers in Michigan. And, at least partly in response to the widely perceived need to reduce greenhouse gas emissions and more fully utilize available renewable resources, many existing U.S. hydroelectric facilities are being refurbished. Improved, higher efficiency hydro generator turbine blade shapes and other associated engineering improvements are resulting in a recent increase of hydroelectric plant improvements. For example, Consumers Energy has announced plans to refurbish its existing hydroelectric facilities to achieve more capacity and energy production from the same impoundments, and Consumers Energy and Detroit Edison are also investing in upgrades to the Ludington Pumped Storage facility, which are predicted to result in a 10-15% increase in the available capacity there.

Figure 10: Dam Inventory Data for HBPW Area



Source: Idaho National Engineering and Environmental Laboratory. (January 2006). *Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plant;* http://hydropower.inel.gov/resourceassessment/pdfs/main_report_appendix_a_final.pdf.

In summary, Staff believes that HBPW's customers will be best served if a thorough technical and economic analysis of such resources is completed, prior to locking into a decision regarding a major investment in a baseload coal facility. Staff believes that during the coming decade or two, many additional hydroelectric resources can be successfully and cost-effectively developed in Michigan, and this form of low-emissions generation will prove to be a useful adjunct to other available renewable energy resources.

[154] MPSC Case No. U-15805 http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=15805. For a summary of Consumers Energy recent renewable energy contracts, see: http://www.michigan.gov/documents/mpsc/ce_pa_295_contract_summary_318346_7.pdf.

[155] MPSC Case No. U-15806, http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=15806. For a summary of Detroit Edison recent renewable energy contracts, see: http://www.michigan.gov/documents/mpsc/dte_pa_295_contract_summary_318322_7.pdf.

Combined Heat & Power (CHP)

HBPW did not provide any assessment of the potential for CHP in or near its service territory. Therefore, it is premature to conclude that CHP is not capable of making a much more significant contribution to HBPW's future resource portfolio.

Staff applauds HBPW for utilizing waste heat from its existing power plant to provide snow melting services. HBPW is to be commended for establishing and maintaining this productive use of waste heat from its existing power plant. However, this use is seasonal, and on the whole a minor use of what is otherwise a much larger source of waste heat.[156]

As shown in Figure 8, there do appear to be several plausible candidates for biomass-fired CHP installations in and around Holland. In addition to those, there may be many other candidates that could consider fossil-fuel or multi-fuel CHP installations. Staff recognizes that completing an inventory of existing facilities that are good candidates for CHP installations is not a trivial task. Nevertheless, workable means exist to guide the Utility or any other entity in this effort.[157]

Although CHP (both large & small scale) might not completely replace the need for new baseload generation in HBPW's portfolio, it can contribute towards reducing, or postponing, the overall amount of future capacity needed.

Renewable Energy Demand-Side Management Options

The subject of this section is renewable energy technologies that are capable of contributing to reduced demands for electricity, rather than generating electricity. The most common examples for Michigan include: solar water heaters, active or passive solar energy used for building space conditioning (any combination of heating and cooling), solar daylighting of schools and offices, biomass-fired boilers and wood-burning appliances, and biodiesel, solar, or wind-powered water pumping.

HBPW apparently did not quantify the potential for such resources to cost-effectively reduce electric power demand and energy use.[158] Staff believes this lack of assessment further demonstrates that HBPW has not yet completed a sufficient analysis of renewable energy resources and technologies available to serve customers in its service territory.

Key Observations

Staff's overall conclusion regarding HBPW's presentation of renewable energy resource options is that the Utility's estimates of renewable energy resources resource availability are too low, sometimes plainly incomplete, and its estimates of the commodity cost of electricity from

[156] Document 0037, p. 13, response to Staff question 43.
[157] See for example the January 2007 *Michigan's 21st Century Electric Energy Plan: Appendix II*, Chapter 5-A; http://www.michigan.gov/documents/mpsc/energyplan_appendix2_185279_7.pdf. Additional market studies and case studies can readily be obtained from the United States Combined Heat and Power Association website (http://www.uschpa.org/i4a/pages/index.cfm?pageid=3308), and from the Midwest CHP Application Center website (http://www.chpcentermw.org/10-00_tools.html).
[158] Document 0037, p. 13, response to Staff question 43.

various renewable energy resources conversion technologies is generally too high, especially for future years in the planning period. In addition, HBPW has failed to account for various economic benefits associated with distributed renewable energy resources generators as part of its analysis of alternative generation technologies. The result is that HBPW appears to have disregarded many opportunities for viable, advantageous renewable energy resources technologies to contribute more significantly to meeting HBPW customers' future energy needs.

In its EGAA, HBPW states, "Estimates for costs and performance parameters were based upon Black & Veatch project experience, past vendor inquiries, and a literature review." Staff inquired about the availability of information in addition to what was provided in the EGAA but the responses generally provided no additional information and referred only to the limited information provided in the EGAA, which is said to be based on Black & Veatch sources, including "proprietary databases." HBPW indicates, "Public data sources were not used for developing cost estimates for [renewable energy resources] technologies."

Staff asked HBPW several questions to attempt to ascertain whether the utility has adequately explored additional renewable project possibilities, especially possibilities within or nearby its service territory. Again, only limited information was made available about the projects already considered and the few that are already under contract with HBPW. The utility generally responded to further information requests by indicating that any additional renewable energy resources projects considered by the Utility are either: (a) those already discussed in the EGAA (Section 2-3); (b) projects not developed enough for serious consideration; or (c) projects covered under "nondisclosure agreements."[159]

The lack of transparency in the HBPW EGAA prevents a closer examination of all of the underlying assumptions. Staff believes this is a serious concern which demands particular attention. This issue, already discussed on Page 29 of this report, is especially serious for renewable energy resources, because renewable energy resource systems costs have changed markedly in recent years due to a combination of changes in the general economy, renewable energy resource market expansions and contractions, and improvements in technology productivity and reliability; along with increasing manufacturing capacities and associated cost reductions.

For example, costs steadily declined for both wind and solar technologies over the past two decades, until 2005, when fast-growing world markets for renewable energy equipment led to a sellers market and prices rose through about 2008. Since then, however, with the substantial slow down in the world economy and continuing growth in wind manufacturing capacity, renewable energy resources equipment prices have fallen substantially.[160] It should be noted that predictions of future renewable energy equipment performance and cost will be subject to forecasting errors. The trends for wind and solar renewable energy resources systems, though,

[159] Document 0037, p. 12, answer to Staff question 37; Document 0053, p. 3, answer to Staff question 10a.
[160] See: Wiser, R., G. Barbose, C. Peterman, and N. Darghouth, October 2009, *Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008*, Berkeley, CA: Lawrence Berkeley National Laboratory; LBNL-2674E; and Wiser, R., and M. Bolinger, July 2009, *2008 Wind Technologies Market Report.* *http://eetd.lbl.gov/ea/ems/emp-pubsall.html*.

do appear to be reliable: technological and manufacturing improvements continue to lead to higher performance at the same or lower cost.

Thus, if the Black & Veatch assumptions were even as little as a year out of date, they could well lead to erroneous conclusions regarding resource selection in the modeling process. And, very importantly, as HBPW looks ahead through the entire 20-year or longer planning cycle, which must be considered when making a commitment to any long-term asset, such as a new coal plant, some consideration should be given to the fact that purchasing decisions for small scale distributed energy resources do not face the same risk profile as associated with a single baseload power plant. For example, a sequence of renewable energy resources purchases over a much longer time horizon might substitute for the one-time investment decision to acquire the proposed new coal plant. When comparing two such different capacity expansion plans, it is critically important to consider the likelihood of, and sensitivities to, future price increases and decreases for the various major pieces of capital equipment and operating expenses. In this circumstance, however, even after determining that some renewable energy resources are already presently available at life-cycle levelized costs only slightly more than the planned coal plant, there is no evidence in the provided documents to indicate that HBPW or Black & Veatch even considered future renewable energy resources systems likely price digression and performance improvements, nor the option of systematic, sequential investment in renewable energy resources.[161]

Combustion Turbine and Combined Cycle

The conventional technologies of the simple cycle combustion turbine and combined cycle combustion turbine were analyzed to find the technology required to meet HBPW projected resource needs. After the initial screening, HBPW was only left with combined cycle technologies for further evaluation, simple cycle technologies were not presented as viable alternatives. The combined cycle technologies further evaluated are displayed in Table 24.

Table 24: Ranking of Selected Expansion Plans and Addition Plans Based on Net System Cost after Adjusting for Benefit Credits and Including CO_2 Allowance Costs

Plan Description	CPWC Value-2010 Dollars (000s)	Levelized Cost ($/MWh)
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 213. New combined cycle unit available in 2016.	1,703,869	71.93
65 MW net combined cycle unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,782,290	75.24

[161] See Document 0053, p. 6, response to Staff Question 16.

HBPW examined the simple cycle combustion turbine technology, however, it was not selected for further evaluation. The screened technology is the LMS100, which is currently the most efficient simple cycle turbine in the world and has the ability to achieve full power from a cold start in 10 minutes.[162] HBPW expects this unit to have a high availability; however, the availability must be demonstrated before the LMS100 can be considered a conventional alternative.[163] Along with this, HBPW resource needs appear to be an intermediate to baseload need rather than a peaking need.[164] The simple cycle turbine is typically used for peaking generation, while the combined cycle turbine may be utilized as baseload generation.

When compared to the simple cycle, the combined cycle technologies have increased efficiencies and the ability to quickly boost output. However, small reductions in plant reliability, higher capital costs and increase in staffing and maintenance requirements due to plant complexity are disadvantages faced by the combined cycle.[165] Along with this, combined cycle units typically require an additional three hours from a cold startup when compared to a simple cycle turbine.[166]

HBPW further evaluated the option to build and own a 65 MW net natural gas fired combined cycle plant and retiring the James De Young Unit 3 coal-fired unit in 2013. The proposed facility provides HBPW the community benefits of a waste heat source for the city's snow melt system. Though this option is higher priced compared to the other combined cycle alternative, HBPW contends it is a feasible and viable option.[167]

The other combined cycle technology further evaluated is the 2 x 1 7EA unit. HBPW evaluated the option of converting an existing combustion turbine (CT9) into a 2 x 1 combined cycle plant at the current CT9 site. The existing turbine is a GE 7EA peaking unit and assumed this plant will be converted into a 2 x 1 combined cycle plant by using the existing CT and adding on another GE 7EA CT.[168] The price of this unit is competitive, along with having the benefit of reduced CO_2 and SO_2 emissions compared to a coal-fired unit. However, this unit does not contain the community benefits of providing a snow melt system when compared to the building of a 65 MW combined cycle plant. Along with the units' size upon completion of the conversion (capacity of over 200 MW)[169] HBPW would need to find purchasers of the remaining capacity to make this a viable option. HBPW recommended continuing to evaluate participation in a gas fired combined cycle unit if other participants can be established.[170]

[162] HBPW EGAA, p. 5-30
[163] HBPW EGAA, p. 5-30
[164] HBPW EGAA, p. 1-3
[165] HBPW EGAA, p. 5-33
[166] HBPW EGAA, p. 5-33
[167] HBPW EGAA Supplemental Case Results
[168] HBPW EGAA, p. 7-5
[169] HBPW EGAA, p. 7-10
[170] HBPW EGAA, p. 9-2

Nuclear

HBPW did not model a scenario that consisted of nuclear generation and has acknowledged that due to public perception, capital costs, and environmental issues, nuclear power faces numerous challenges in the United States.[171] However, due to increasing fuel prices, greenhouse gas emission concerns and increasing energy demand projected by HBPW, it is believed that nuclear plants may be a viable option for producing power in the future.[172]

HBPW provided information regarding two potential nuclear reactors in its analysis: the Westinghouse AP-1000 (1,140 MW) and the General Electric (GE) ESBWR (1,500 MW). The AP-1000 possesses a proven technology designed around simplification and safety in order to create a plant that is easier and less expensive to build, operate, and maintain.[173] The GE ESBWR is a globally used reactor technology that accounts for one-third of the United States installed base[174] and provides a simplified design to reduce the number of active systems and increase the safety of the plant.[175]

The cost characteristics of a nuclear power plant were submitted by HBPW. In 2009 dollars, a typical nuclear facility would contain a total project cost of $6,000/kW. This creates a levelized cost of $99/MWh at an 80% capacity factor and a levelized cost of $85/MWh at a 95% capacity factor.[176]

According to HBPW, nuclear plants are competitive producers of electricity compared to coal-fired plants and are much less sensitive to changes in fuel costs.[177] Along with this, having no fossil emissions from the reactor directly connected to power generation is an important attribute due to potential carbon constraints.[178] However, the analysis provided by HBPW states, "The large capacity of a nuclear unit would not be practical for a small utility to build on its own, however, it is possible for a small utility to participate in a share of a nuclear unit if one is built by others nearby."[179] Staff concurs that the building of a nuclear plant would not be suitable for HBPW's specific needs.

Purchased Power

HBPW explains its views of the use of purchased power on its website. "The Holland Board of Public Works can also purchase power on the open market. HBPW staff monitor the cost of power and make purchasing decisions every hour of every day of the year. The cost of buying electricity from other facilities fluctuates significantly. There are times when the cost of

[171] HBPW EGAA, p. 5-44
[172] HBPW EGAA, p. 5-44
[173] HBPW EGAA, p. 5-44, 5-45
[174] HBPW EGAA, p. 5-46
[175] HBPW EGAA, p. 5-47
[176] HBPW EGAA, p. 5-49
[177] HBPW EGAA, p. 5-45
[178] HBPW EGAA, p. 5-48
[179] HBPW EGAA, p. 5-44

purchasing power is much higher then the cost of generation as well as times when it more cost effective to buy power from other producers."[180]

According to HBPW, "historically, HBPW as met more than 90 percent of its peak and energy requirements from self-owned generating resources and has utilized market-priced purchased power transactions to meet its remaining peak demand and energy requirements."[181] Within the context of its supply plan, HBPW evaluated purchases from the wholesale energy market, as well as long-term power purchase agreements with other proposed new generation.

As part of the technology screening, HBPW provided levelized cost estimates for building alternative technologies as well as purchasing power produced by alternative technologies. The following table lists levelized cost estimates for each technology where a comparison was provided for built versus purchased technologies.

Table 25: Levelized Cost Estimates Comparing Building vs. Purchased Power for Various Technologies

Technology	Source Table (within HBPW's Supply Plan)	Levelized Cost – Municipal ($/MWh)	Levelized Cost – PPA ($/MWh)
Direct Biomass Combustion	Table 5-1 p. 5-8	100 to 150	120 to 150
Biomass Co-firing	Table 5-2 p. 5-11	40 to 50	30 to 40
Landfill Gas	Table 5-3 p. 5-13	70 to 85	60 to 90
Wind - Onshore	Table 5-5 p. 5-17	90 to 110	100 to 150
Wind – Offshore	Table 5-5 p. 5-17	100 to 150	160 to 260
Parabolic Trough	Table 5-6 p. 5-20	550 to 700	300 to 400
Solar PV - Crystalline	Table 5-7 p. 5-22	450 to 550	250 to 300
Solar PV – Thin Film	Table 5-7 p. 5-22	300 to 350	180 to 220
Hydroelectric	Table 5-8 p. 5-25	90 to 110	115 to 140

While some technologies appear to result in lower levelized cost estimates if they are purchased versus constructed by the municipal, Staff notes that in several cases, the ranges overlap each other, and the purchase versus build decision is not obvious. Staff questioned HBPW regarding the derivation of these estimates and whether or not HBPW had issued requests for proposal to develop the estimates shown in the plan for PPAs. HBPW responded that the PPA numbers "are not based on any request for proposal process, and there are no specific PPA terms assumed. These are generic approximate ranges that assume that the energy from the given technology is

[180] Holland Board of Public Works | Electric | Base Load Generation; http://www.hollandbpw.com/ELECTRIC/Pages/BaseLoadGeneration.aspx.
[181] HBPW EGAA, p. 7-2.

purchased through a PPA from an independent power producer or other entity that can take advantage of potential production or investment tax credits which are not available to tax exempt entities."[182]

The strategist model utilized for HBPW's supply plan included both emergency energy purchases and economy energy purchases. "Strategist utilized economy energy purchases from the market to meet the system energy requirements when the energy price in the market was lower than the cost of generating electricity from the most efficient and least-cost available generating resource or purchase agreement available to HBPW."[183] Consistent with HBPW's historic operations, spot market purchases within the strategist model were limited to ten percent of HBPW's need. While Staff acknowledges that HBPW has not previously purchased more than ten percent of its requirements, Staff notes that it may prove beneficial for HBPW to evaluate whether or not there may be advantages in purchasing larger quantities in the near-term and this ten percent assumption in the Strategist model precluded such evaluation.

"Black & Veatch evaluated the options of buying shares of the proposed 800 MW supercritical PC unit to be built at Karn-Weadock by Consumers Energy in Bay City, Michigan and the 2x300 MW CFB units proposed to be built in Rogers City, Michigan by Wolverine Electric Cooperative. Both these options are in the advanced stages of planning with forecast commercial online dates in 2016. The availability of these units coincides with the needs of HBPW, Black & Veatch evaluated these options for this study."[184] Three different expansion plans involving purchased power ranked in the top five according HBPW's supply plan:[185]

- Fully optimized case. Buying 5 MW blocks of all coal and CFB units (except CCS units), and all generic units are available in 2016.
  (Rank #2 out of 10)
- Buying 5 MW blocks of 2x300 MW CFB unit at Rogers City in 2016.
  (Rank #3 out of 10)
- Buying 30 MW block of 800 MW SCPC unit at Weadock in 2016.
  (Rank #4 out of 10)

Although the above expansion plans utilizing purchased power ranked high as compared to many other of HBPW's expansion plans that were analyzed, they are not without risk. The fully optimized case that examined coal purchases in 5 MW blocks allowed the strategist model to select smaller amounts of capacity at discreet points in time as opposed to much larger chunks. HBPW explains that "however, in the real world, it is difficult to acquire small capacity blocks of generating resources every year, because whole plants have to be constructed once the decision is made rather than building fractional units."[186] Although the fully optimized case provides useful information, it does not appear to be a feasible planning scenario for implementation.

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[182] Document 0037, p. 2, response to Staff question #2
[183] HBPW EGAA, p. 7-2.
[184] HBPW EGAA, p. 7-4.
[185] HBPW EGAA, p. 7-11.
[186] HBPW EGAA, p. 7-8.

Similarly, the expansion plan incorporating purchases of 5 MW blocks from the proposed Rogers City CFB units may prove difficult to negotiate due to the nature of the relatively small purchase amount. Although the proposed timing for the proposed Rogers City plant is near the timing of HBPW's capacity need, at the present date, air permit was denied by the DNRE. While HBPW may be able to negotiate a power purchase agreement with Wolverine at some point in the future, the Rogers City project, with the advent of the DNRE decision to deny the air permit, does not seem like a viable option.

HBPW also examined a 30 MW power purchase agreement from Consumers Energy's proposed 800 MW expansion at Karn-Weadock. This expansion plan is more feasible than the other two power purchase plans because of the larger purchase amount, and because Consumer's Energy has received an air permit for the capacity expansion at Karn-Weadock. Relying on a future purchase from a plant that is still in preliminary stages is not without significant risk because many other proposed capacity expansions in the United States have been cancelled in recent years. In the short time that has passed since HBPW filed its EGAA, Consumers Energy has placed the proposed Karn-Weadock facility on hold indefinitely.

Within the technology screening, HBPW provided estimates that were described as generic approximate ranges for levelized costs of purchased technologies. In comments, First Energy Solutions challenges HBPW's review of purchased power options. "Prior to concluding that purchased power is not appropriate in this instance, it would be reasonable for Black & Veatch to conduct the necessary request for proposals ("RFPs") to determine whether and under what terms and conditions purchased power arrangements could be made. FES sees no evidence in the EGAA that this has been done."[187] Staff contends that steps should be taken to formalize those cost estimates before proceeding with the construction of a new facility.

Many public comments 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. HBPW concurs stating "to ensure that adequate supplies are available and reliable service is provided to customers, it is generally not recommended to rely on large amounts of market purchases."[188] The Midwest ISO IMM's 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." [189] Staff contends that HBPW should relax the assumption that only ten percent of the requirements should be met with purchased power in the near-term to allow evaluation of such an alternative.

First Energy Solutions contends that "power prices in MISO are currently at very low levels compared to recent historical levels."[190] Staff notes that while market prices are currently low,

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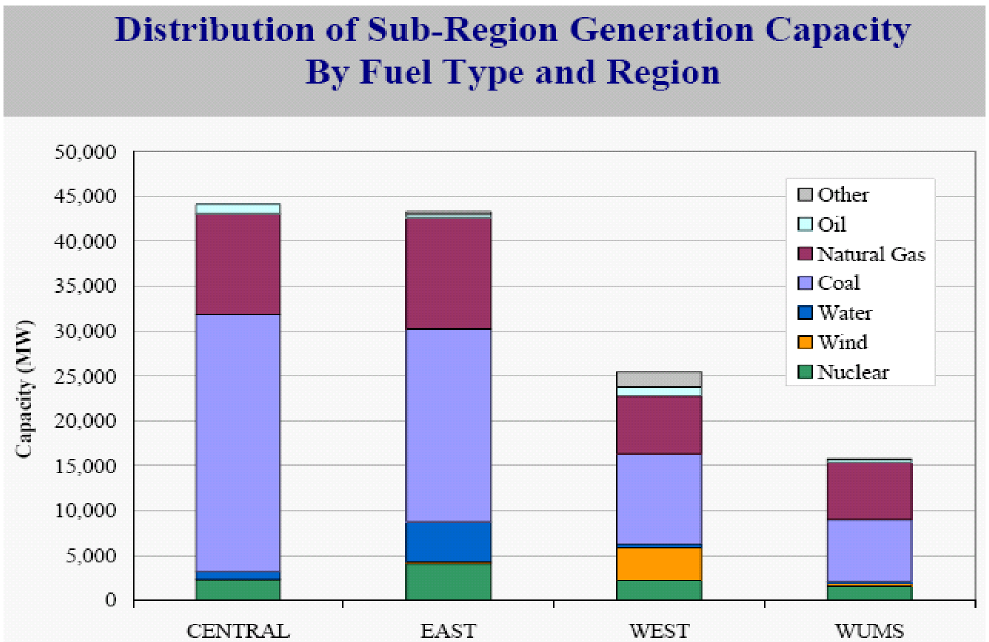
[187] Comments of First Energy Solutions, http://efile.mpsc.state.mi.us/efile/docs/16077/0025.pdf, p. 5.
[188] HBPW EGAA, p. 7-2.
[189] 2008 Midwest ISO IMM's State of the Market Report, MIDWEST ISO IMM SOM Report 2008, http://www.Midwestmarket.org/publish/Document/6ef35b_121e89707ed_-7dcf0a48324a/2008%20Midwest%20ISO%20State%20of%20the%20Market.pdf?action=download&_property=Attachment, 6/26/09, p. 55.
[190] Comments of First Energy Solutions, http://efile.mpsc.state.mi.us/efile/docs/16077/0025.pdf, p. 5.

the historic volatility in market prices may likely continue out into the future, especially considering the pending changes in the industry including renewable mandates, and potential climate change legislation.

Many of the public comments received recommend that the company purchase power as opposed to building a coal-fired plant due to concerns about carbon dioxide and global warming. Purchases from the Midwest ISO region are often backed by coal-fired generation. The Midwest ISO IMM's SOM report details the capacity by fuel type in the Midwest ISO region:[191]

Figure 11: Fuel Type Distribution by Region



While Figure 11 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-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.

Reliance on the energy market for purchases exposes customers to a significant amount of risk, from both higher energy prices, and potential future costs associated with carbon legislation.

[191] Midwest ISO IMM SOM Report 2008, 6/26/09, p. 59.

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 HBPW, 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 HBPW's EGAA as it relates to long-term investment decisions of this nature.

HBPW's EGAA filing does not constitute an Integrated Resource Plan (IRP), as outlined and required 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 HBPW'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:

- HBPW failed to adequately demonstrate the need for the proposed facility as the sole source to meet its projected capacity requirements. Given Michigan's recent economic recession and uncertainty concerning the time frame for economic recovery, HBPW's forecasted annual demand growth rate of approximately 2.1% appears overly optimistic. Load growth in the early years is dependent upon some key industrial load additions, which have a significant impact on the overall load forecast. Furthermore, the amount of peak demand reduction potential through energy efficiency and other demand-side strategies assumed within HBPW's supply plan appears unduly conservative. Under-estimating the potential impact of energy efficiency in future years, coupled with an overly optimistic load forecast results in a projected capacity need which may not fully materialize.

- HBPW analyzed only one base case scenario in their resource expansion plans. However, one sensitivity pertaining to CO2 allowance prices was included in their analysis. HBPW acknowledged that additional sensitivities for load growth and fuel prices were not performed. Scenario analysis should be employed across a wide range of variables and sensitivities including: future load levels, fuel prices, renewable energy penetration levels, energy efficiency penetration levels, and other variables which impact future resource planning in order to properly evaluate the associated risks.

- Purchased power options were not fully explored as they were limited to only ten percent of the total requirement within the model. Staff recommends further evaluation of purchased power options that may be available to HBPW over the next several years.

- As acknowledged in HBPW's EGAA filing, 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 less costly alternatives were noted in the EGAA and could be selected to meet HBPW's expected capacity shortfall, if so desired. Other options that could fill all, or portions, of the projected capacity need include: a combined cycle natural gas plant, purchase power options or a combination of alternatives that could lead to lesser amounts of purchased power, energy efficiency and load management, and renewable generation resources.

- Staff also notes that HBPW is a municipal utility, not traditionally regulated by the Michigan Public Service Commission. As such, HBPW's Board and management are solely responsible for evaluating risk and making financial decisions for the utility and the customers it serves.

Appendices

A. DNRE – 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

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