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In the Matter of Minnesota Power's 2010 Integrated Resource Plan Filing — **PUC Docket No. ET2/RP 09-1088**

INITIAL COMMENTS OF IZAAK WALTON LEAGUE OF AMERICA-MIDWEST OFFICE, FRESH ENERGY, AND MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY

I. INTRODUCTION

The Izaak Walton League of America – Midwest Office, Fresh Energy, and Minnesota Center for Environmental Advocacy ("Environmental Organizations") submit these comments on Minnesota Power's 2010 Integrated Resource Plan ("IRP"). Environmental Organizations primarily challenge Minnesota Power's decision to present an IRP that assumes without analysis that it is least cost and otherwise in the public interest to continue operation of its entire aging coal fleet for the duration of the fifteen-year planning period. At a time when numerous federal environmental regulations that would impose more stringent requirements for coal plants are pending, proposed and/or expected, Minnesota Power's failure even to consider the potentially more favorable economics of scenarios that retire one or more units in the Company's coal fleet is not prudent. Moreover, these comments identify several erroneous modeling assumptions upon which the Minnesota Power IRP relies that further weaken the Company's position that it is in the public interest for the Commission to approve its IRP.[1] Environmental Organizations respectfully request that the Commission direct Minnesota Power to carry out new analysis that both corrects modeling flaws identified in these comments, and examines in detail the economics of retiring coal units on the Minnesota Power system.

II. BACKGROUND AND SUMMARY OF COMMENTS

Minnesota Power (MP) filed its IRP on October 5, 2009. The IRP presents MP's forecasted electric demand for the period 2010-2024 and its plan to meet that demand with additional supply and demand-side resources, above an established reserve margin. To perform its resource planning, MP established a given set of assumptions in addition

[1] Environmental Organizations obtained substantial technical assistance in the preparation of these comments from the Synapse Energy Economics consulting firm in Cambridge, Massachusetts.

to its load forecast, which include assumptions on fuel prices, capital costs and operating costs for various generating technologies, transmission, and the costs associated with likely carbon dioxide allowances (as required by Minn. Stat. §216H.06). Resource options are then chosen based on those input assumptions. MP included five different scenarios for the future in the IRP: the Reference Case, Green Focus, Green Growth, Slow Business, and Back to Business. The primary focus of MP's IRP, as well as the focus of these Comments, is the Reference Case scenario.

MP analyzed scenarios using two different models, the RTSim production cost model, and the Strategist expansion planning model (the "Model"). The Strategist model was also used in the preparation of these Comments.

MP expects the economy to begin recovering from the recent and ongoing recession, and anticipates the gradual increase of electricity demand from the industrial customers that make up a significant portion of its load. In order to comply with state laws requiring specific amounts of energy efficiency (1.5% of sales) and renewable energy (25% of sales by 2025), as well as consideration of likely federal laws governing the emissions of carbon dioxide (CO_2), the Strategist model selects (based on MP's input assumptions) a specific amount of energy conservation and demand response over the planning period, the addition of 500 MW of wind generation, short term market purchases, and a long-term capacity and energy purchase from Manitoba Hydro. The resulting net present value (NPV) of MP's plan is $3.81 billion.

However, MP makes a number of faulty input assumptions that significantly affect the results of its resource optimization modeling and the Company's recommendations about future resource additions and costs. In sum:

1. MP does not model incremental energy efficiency and peak demand response in a way that allows the selection of the maximum amount of conservation that is achievable and cost-effective;
2. the Company unreasonably limits the amount of wind available to the Strategist model, both incrementally and cumulatively, thus adding a lesser amount of wind generation to the resource plan than might otherwise be chosen;
3. capital costs of wind are set at an escalation rate of **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** when several sources believe that future capital costs will actually decline;
4. the NPV of MP's Reference Case is artificially low because future fixed O&M costs for existing coal units are not properly considered in Strategist, and MP's assumed future variable O&M costs are much lower than MP has historically reported;
5. aside from inclusion of an allowance price for CO2 emissions, as mandated by Commission Order, MP does not do any analysis of future federal air and environmental regulations or the associated costs on the MP system; and,
6. at no point in the modeling analysis does MP examine any scenarios in which any of its coal-fired generating units are retired.

While the last point is the most important, the first five points affect the input assumptions that drive the valuation of a Reference Case and any associated retirement scenarios. Synapse Energy Economics utilized the Strategist model to examine the effect of the input assumptions on MP's Reference Case scenario and to evaluate a number of retirement scenarios using MP's own input assumptions. Results from these retirement scenarios show that the retirement of one or more of MP's coal units would result in a lower NPV than in MP's Reference Case, *even when MP's assumptions remain unchanged*.

Synapse then increased the limitations on wind in Strategist and increased the fixed and variable O&M costs at MP's coal units to conform to the Company's historical costs, and re-ran Strategist to produce a Synapse Reference Case and an additional set of retirement scenarios. *No other changes were made to MP's input assumptions*. Adjusting the operating costs of existing coal units just to conform to MP's historical O&M costs necessarily increases the NPV of the Synapse Reference Case, but makes retirement scenarios look more attractive from an economic perspective.

It is essential to recognize that the limited adjustments reflected in the Synapse Reference Case do not include *any* adjustments to account for the increased capital and operating costs for MP's existing coal units that would result from compliance with any of a large number of expected federal regulatory changes discussed later in these comments that would impact the economics of continued operation of MP's coal-fired electric generating units. In other words, the Synapse Reference Case is a very conservative one.

Based on the analysis of MP's input assumptions and the Synapse Strategist modeling results, we recommend the following actions:

1. MP should perform analysis of upcoming federal environmental regulations and their cost effect on existing MP generation units;
2. MP should do a DSM potential study and model additional incremental levels of energy conservation and peak demand response;
3. Increase or remove limitations on wind additions, and MP should reexamine wind capital costs;
4. Adjust future fixed and variable O&M costs upward for existing coal units to accurately represent historical costs of MP's existing fleet; and
5. MP should consider and analyze various scenarios that retire one or more existing coal units, and should present those for PUC review *before* its next regularly scheduled IRP filing.

The following sections examine MP input assumptions in more detail, present the results of the Synapse modeling analysis, and make recommendations for future actions by MP.

III. MP'S STRATEGIST MODELING IS FLAWED.

A. MP Fails to Analyze the Potentially Significant Impacts of Future Environmental Regulations.

The Company's proposed IRP comes at a time of important transition for the electric industry. It is essential that MP take steps to analyze the impact of a multitude of announced or expected future environmental regulations on the viability of units in MP's coal fleet.

EPA has announced its intention to ensure better air quality, promote a cleaner and more efficient power sector, and have strong but achievable reduction goals for SO_2, NO_X, mercury, and other air toxics. One of EPA's first initiatives in this effort came in July 2010, with EPA's proposed transport rule intended to reduce transport of pollutant that contribute to nonattainment of National Ambient Air Quality Standards (NAAQS) or that interfere with maintenance of those standards by downwind states.[2] Under the July proposal, reductions in emissions of SO_2 and NO_X from electric generating units in Minnesota will be required because of their effect on the ability of downwind states to comply with the 24 hour PM 2.5 NAAQS (promulgated in 2006) and the annual PM 2.5 NAAQS (promulgated in 1997).

In the July 2010 proposal, EPA identified a preferred approach, but will also take comment on two alternatives. All three approaches would cover the same states – 31 states and the District of Columbia, set a pollution limit (or budget) for each state and obtain the reductions from power plants. EPA's preferred approach and the first alternative would both allow trading of emissions allowances among power plants within a state, with the preferred approach even allowing some limited trading between states. The third approach would allow averaging among a power plant owner's in-state generating units. Under these approaches, emissions allowances, and the avoidance of emissions (which frees up allocated allowances for trade), have economic value that must be taken into account in evaluating future use of existing units. EPA determined allowance prices for emissions of SO_2 and NO_x under its preferred approach using its IPM model. Those modeling results are shown in Table 1, below.

Table 1. Projected Allowance Prices for State Budgets/Limited Trading Approach (2006$).[3]

	2012	2014
Annual NOx	$500	$500
Ozone-season NOx	$500	$500
Annual SO_2 - Group 1	$1,000	$1,100
Annual SO_2 - Group 2	$800	$300

[2] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010 / Proposed Rules, pp. 45210 ff.
[3] US Environmental Protection Agency, Office of Air and Radiation. *Regulatory Impact Analysis for the Proposed Federal Transport Rule*. June 2010. Page 383.

EPA projected prices for allowances in the state of Minnesota to be \$500/ton for NO_x allowances in both 2012 and 2014, while prices for SO_2 allowances were determined to be \$200/ton in both years.[4] Minnesota Power's modeling assumption that these emissions have a value of \$0 is likely to be incorrect, and this assumption will understate the benefits and cost savings associated with the near-term retirement of its thermal generating units.

The transport rule proposed July 2010 is only the first of several rules to be issued over the next couple of years that will regulate emissions from power plants and affect the economics of continuing to emit both criteria and hazardous air pollutants. Perhaps the most important of these addresses section 112(d) of the Clean Air Act (CAA), which regulates emissions of mercury and other hazardous air pollutants (HAPs) for electric utilities, which will be proposed by March 2011 and finalized by November 2011. More than 180 HAPs are listed under the CAA. This rule would require that sources be retrofitted with the Maximum Achievable Control Technology (MACT), taking into consideration costs, energy requirements, and non-air quality health and environmental impacts. For existing sources, this means that control technologies must be at least as stringent as those installed on the average of the top twelve percent of performing major sources. Requirements for new sources are at least as stringent as the single best performing source. Existing units will have three years to comply with the final rule once it is issued; new sources will have to comply immediately upon issuance of the rule.[5]

While the proposed federal electric utility MACT rule will not be released until spring 2011, EPA has already released its MACT rule for industrial boilers, with emissions restrictions based on boiler size. The vacated Clean Air Mercury Rule applied to units greater than 25 MW in size. These rules seem to indicate that EPA's electric utility MACT will also limit emissions of HAPs based on unit size, and that the baseline will be small. Even the smallest of thermal units in MP's portfolio, then, may be required to install some type of emissions controls – whether that is ACI, FGD, SCR, etc. – in order to meet forthcoming regulations.[6]

The cost per kW of emissions control technologies like FGD and SCR increases as generating units get smaller due to economies of scale in their design and construction. Figure 3 shows the capital costs of FGD retrofits for generating units of different sizes, and Figure 4 shows the same information for retrofits for NO_x controls, as estimated by the Electric Power Research Institute (EPRI).

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[4] US Environmental Protection Agency, Office of Air and Radiation. *Regulatory Impact Analysis for the Proposed Federal Transport Rule*. June 2010. Page 384.

[5] Joe Bryson, US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 17.

[6] As the Commission is well aware, the state of Minnesota already has on the books mercury regulations that have taken effect for certain existing large power plant units. The Minnesota Mercury Reduction Act, Ch. 216B.68 *et seq.*, requires electric power plants with a combined capacity of more than 500 MW from all units combined, and single units greater than 100 MW, to submit plans for mercury reductions that would reduce emissions of mercury by 90%.

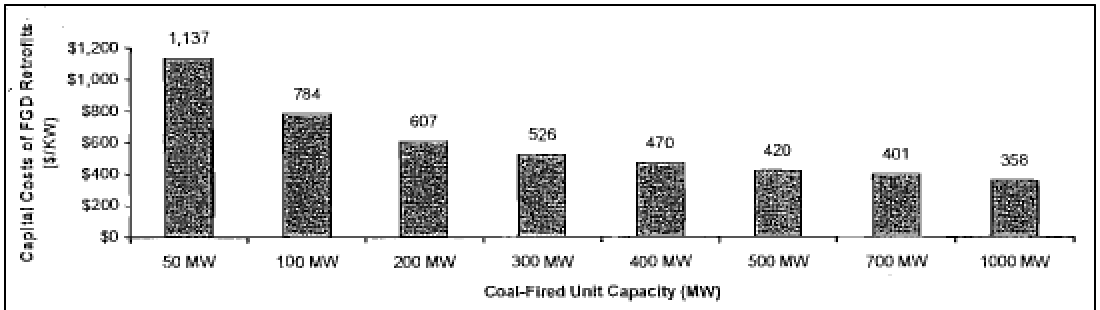

Figure 1. Capital Costs of FGD Retrofits ($/kW).[7]

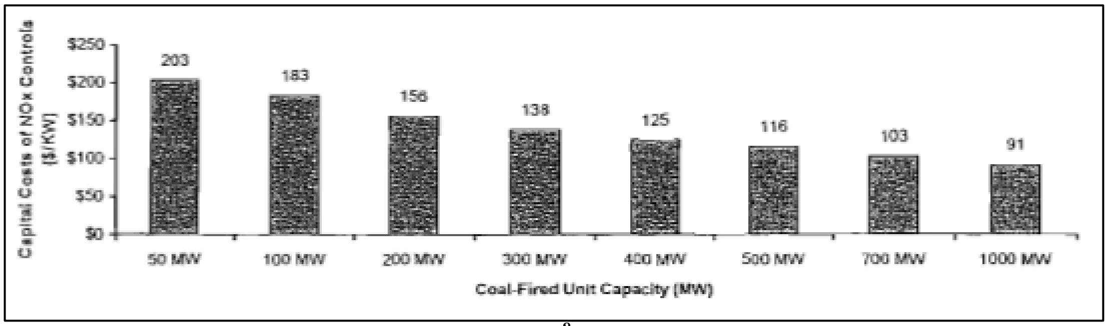

Figure 2. Capital Costs of NOx Retrofits ($/kW).[8]

Costs of retrofitting MP's smaller units that are currently lacking these emissions controls could therefore be quite high. In addition to added capital costs, emissions control technologies also lead to increased operating costs for units, and costs associated with capacity deratings.

Moreover, costs for emissions controls have increased in recent years. Perhaps the clearest example is Allegheny Power's Fort Martin plant. This 1,152 MW plant has been listed in a number of filings with the Public Service Commission of West Virginia for cost recovery approval for the installation of a wet FGD system. In its April 2005 filing, Allegheny estimated the installation costs as $332 million.[9] In a 2006 filing this estimate was increase to $450 million, and in a July 2009 filing this estimate was increased once again to $550 million.[10] The reason given for the increase was "site-specific conditions" as evaluated by the installation's prime contractors.

Other anticipated federal regulatory actions include potential rules to address pollution transport under revised NAAQS, revisions to new source performance standards (NSPS) for coal and oil-fired utility electric generating units, and implementing best available retrofit technology (BART) and regional haze program requirements to protect visibility. Further, EPA will continue with its ongoing reviews of the ozone and PM2.5 NAAQS, which could result in revised NAAQS. Following any new NAAQS, EPA would propose

[7] Bernstein Research. *U.S Utilities: EPA Announces its Proposed Transport Rule to Replace CAIR; How Will the Coal Fleet Be Affected?*. July 7, 2010. Page 9.
[8] Bernstein Research. *U.S Utilities: EPA Announces its Proposed Transport Rule to Replace CAIR; How Will the Coal Fleet Be Affected?*. July 7, 2010. Page 10.
[9] PSC of West Virginia, Case No 05-0402-E-CN, June 23, 2005.
[10] PSC of West Virginia, Case No 05-0402-E-CN, September 30, 2009.

interstate transport determinations in future notices. Those proposals could require greater emissions reductions from states covered by this proposal. Thus, utilities should prepare for a range of expected emissions regulations, like ozone and regional haze, in a comprehensive manner.

Finally, the spill of coal ash at TVA's containment facility prompted the EPA to regulate coal combustion residuals (fly ash, bottom ash, boiler slag, and FGD materials) for the first time, in order to address the risks of disposal of these wastes. EPA's proposed "Disposal of Coal Ash Residual's Rule from Electric Utilities" was issued on June 21, 2010, and regulates coal combustion residuals under the Resource Conservation and Recovery Act (RCRA). EPA proposed two approaches which mandate engineering requirements for disposal facilities, e.g., liners, groundwater monitoring, etc., but differ in terms of enforcement and implementation. The effect of this rule on MP's coal combustion residuals disposal practice, capacity, and costs must be examined in detail.

MP's IRP does not include any analysis of the potential effect of any of these upcoming regulations, and thus cannot be considered to be a reasonable plan for the future.

B. MP Should Model Additional Energy Efficiency Savings and Peak Demand Reduction Scenarios.

1. Energy Efficiency

In accordance with Minnesota's Next Generation Energy Act of 2007, Minnesota Power (MP) has committed to an energy efficiency savings goal of 1.5% per year, which implies an estimated cumulative annual savings of 1,290,000 MWh in 2024.[11] In its IRP, MP refers to this 1.5% as its "Base Plan" and includes it in Strategist as a reduction in MP's load forecast. MP also includes two alternative conservation options, which the Model can choose in its optimization. Alternative 2 results in approximately 13 MW of additional energy savings by 2024, for a cumulative conservation savings of approximately 1.8%, which implies an estimated cumulative annual savings of 1,550,000 MWh in 2024.[11] Alternative 3 results in approximately 33 MW of additional energy savings by the end of the study period, which results in cumulative energy savings of more than 2.2%. When offered the choice, Strategist chooses Alternative 2 in each of the five planning scenarios, but fails to choose Alternative 3 in any of those scenarios.

According to Minnesota's Office of Energy Security, MP has historically achieved greater than the 1.5% Base Plan energy efficiency savings, on average, between 2004 and

[11] Assuming at least a 15 year measure life and that the savings is only achieved by non-exempt customers that represent a constant 51% of annual sales. As the PUC has done in previous IRP orders, we ask that it document in these implied cumulative conservation savings in the Order in this docket, to highlight the overall magnitude of the conservation impact and importance of this resource. This overall magnitude of about 10% of annual energy usage in 2024 is not well represented in the MP IRP documents graphs, which only show "Expanded Conservation" with a much smaller contribution.

2008. Average energy efficiency savings is reported for Minnesota's investor-owned utilities in Table 1, below.

Table 2. Historical Annual Average Savings and 2010 Goals.[12]

Electric Investor-Owned Utilities	Average Annual Sales (MWh)	2004-2008 Avg. Annual % Savings	2010 % Savings, Planned
Alliant Energy	852,534	1.9	1.5
Minnesota Power	3,298,723	1.8	1.5
Otter Tail Power	2,077,284	0.7	1.0
Xcel Energy	30,815,330	0.9	1.1

The average annual energy efficiency savings, as reported by MP, between 2004 and 2008 was 1.8%. It comes as no surprise, then, that Strategist would choose to add additional energy conservation to the MP Base Plan equal to the savings that MP has achieved in previous years. According to MP, the levelized cost of Alternative 2 is **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** and because Strategist takes Alternative 2 in every planning scenario presented by MP, this is clearly a cost-effective option. Alternative 3, however, represents a large incremental increase in conservation savings with 33 MW of additional energy savings over the Base Plan at a levelized cost of **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** Because Strategist never selects Alternative 3 as a resource addition, MP has concluded that this is not a low-cost alternative.[15]

However, by modeling only these two particular alternatives, MP did not do a proper analysis of incremental energy conservation. There are levels of energy conservation savings that fall between Alternative 2 at [**TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** and Alternative 3 at **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** Because energy efficiency is widely known as the "first fuel," and, in many regions, is considered to be the fastest, cheapest, and cleanest way to meet future energy needs, MP should first look to conservation to meet its future resource needs and should do a study of the technical and economically achievable potential for electricity conservation and peak demand reductions in its service territory.[16] A DSM potential study would serve two purposes: it would first determine the levels of incremental savings and their associated costs that should be presented to the Strategist Model as resource options, and second it

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[12] Minnesota Office of Energy Security. *2007 – 2008 Minnesota Conservation Improvement Program Energy and Carbon Dioxide Savings Report*. January 15, 2010. page 4.

[13] Minnesota Power Responses to MCEA Informal Questions on 2010 IRP. Email August 6, 2010.

[14] *Ibid.*

[15] Cost-effectiveness – measured as benefits of programs exceeding costs – of these and other energy conservation alternatives should not be determined using the Ratepayer Impact Measure (RIM) Test. Table 5.2 on page six of Appendix B – Part 2 demonstrates that each of the alternatives has significant benefits, with all of the measures passing the Societal and Utility Tests. Rejecting alternatives such Alternative 3 based on the RIM Test is extreme.

[16] Minnesota Power Response to MCEA Question 62. August 4, 2010.

would inform the design of conservation programs to help realize untapped efficiency potential. MP should then analyze smaller increments of additional energy conservation as determined by the potential study, over and above the 1.8% it has historically achieved and that was consistently selected by the Model, in order to determine the maximum amount of cumulative energy conservation savings that MP's model would identify as a cost-effective option.

2. Demand Reduction

In addition to achieving greater annual energy conservation savings, Minnesota Power has the potential to achieve greater reductions in peak demand. According to Strategist Model outputs, the interruptible demand reductions achieved by MP are **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** in 2010 and **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** every year thereafter through the end of the study period. These reductions and their effect on peak demand are shown in Table 3.

Table 3. Peak Demand Reductions as Shown in the Minnesota Power Reference Case.

	Peak Load (MW)	Peak Reductions from Interruptible Demand (MW)	% Savings
[TRADE SECRET MATERIAL BEGINS			

TRADE SECRET MATERIAL ENDS]

A study done by the Federal Energy Regulatory Commission (FERC) estimated the potential to reduce peak demand in each of the states. The potential for the state of Minnesota is shown in Table 4.

Table 4. Potential Peak Demand Reductions in the State of Minnesota.[17]

	2014	2019
Business-as-Usual	12%	12%
Expanded BAU	13%	13%
Achievable Participation	15%	16%
Full Participation	16%	19%

The difference between the Business-as-Usual and Full Participation scenarios is the difference between the level of demand response that is being achieved in Minnesota today and what could be achieved if all cost-effective demand response policies were implemented. As shown in Table 4, Minnesota could achieve an additional 4% in peak demand savings by 2014, and an additional 7% of savings by 2019. Key drivers of this potential estimate were identified by FERC, and include: a significant amount of existing demand response in the state, an above average share of peak demand (30%) in the Large Commercial and Industrial classes, and a large residential base.[18]

Figure 3, below, provides a break-down of potential peak demand reductions by customer class and policy.

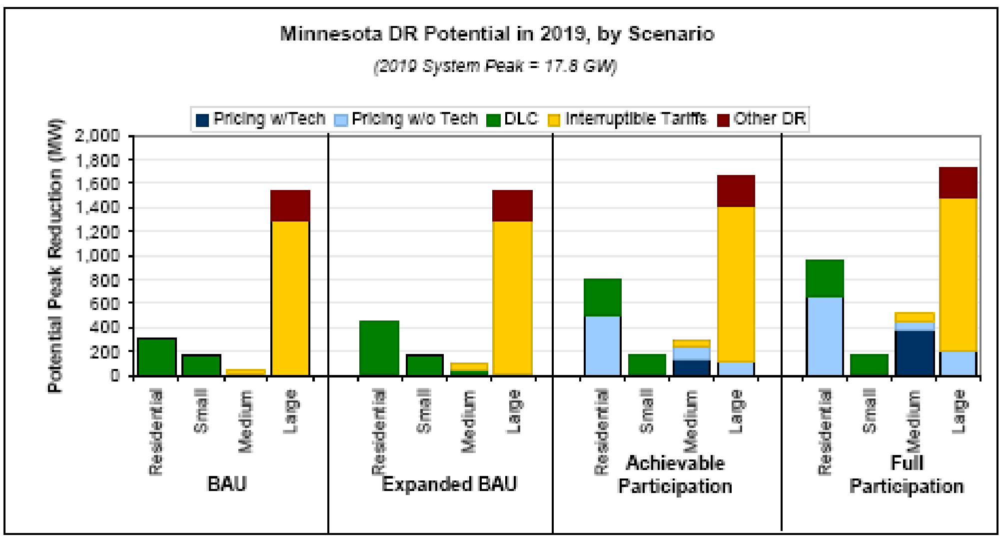

Figure 3. Minnesota Demand Response Potential in 2019, by Customer Class and Scenario.[19]

According to FERC estimates, an additional 650 MW of peak demand savings are achievable in the Residential sector by 2019. An additional 450 MW can be saved in the Medium Commercial and Industrial Sector, and an additional 200 MW can be saved in the Large Commercial and Industrial Sector. These additional savings are predicted to be

[17] :Federal Energy Regulatory Commission (FERC). *A National Assessment of Demand Response Potential*. June 2009. pages 81-82.

[18] Federal Energy Regulatory Commission (FERC). *A National Assessment of Demand Response Potential.* June 2009. page 129.

[19] Federal Energy Regulatory Commission (FERC). *A National Assessment of Demand Response Potential*. June 2009. page 129.

achieved through direct load control programs for residential customers and through dynamic pricing programs for medium and large C&I customers.

While FERC's estimates of demand response potential are for the state of Minnesota as a whole, the results indicate that it may be possible for MP to achieve greater peak demand reductions than it has modeled here. A DSM potential study would again be important in determining how much peak demand response is available in MP service territory. Because MP is unique and the residential load served by the Company is small, a study would also assist in the determination of the load classes with the most potential for peak reductions, as well as serve to verify the savings that should be achieved by industrial customers.

MP should model incremental peak demand reductions in order to determine the least-cost option going forward.

C. MP Imposes Unreasonable Modeling Constraints On Future Wind Additions.

1. Limits on Maximum Addition of Wind Capacity

In the IRP and associated underlying modeling scenarios, MP limits the amount of wind that can be selected by the Strategist model, only allowing **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** to be built over the span of the entire planning period and a maximum of **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** added in any given year. MP states that "this limitation was put into the expansion modeling to capture realistic build potential with the current DC Transmission Line capability to deliver North Dakota Wind energy economically."[20] In MP's Reference Case scenario, Strategist reaches both the cumulative and incremental maximum for wind additions, adding **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** and the final **[TRADE SECRET MATERIAL BEGINS SECRET MATERIAL ENDS]**.

Rather than limiting the amount of wind that can be selected based on the capability of a single transmission line, MP can and should instead investigate and determine the amount of economical wind energy that is actually available in the greater MISO region, and then maximize the wind energy added to the extent that it is economic. Because MP is contained in the MISO region and benefits from the regional dispatch and settlement process, the Company can purchase the output of wind resources located anywhere within the MISO market region. Provided that the Company registers its wind energy purchases with MRETS, MP is not constrained, for the purposes of meeting energy obligations for its Minnesota load, to specific locations on one end of a transmission line that extends into North Dakota. MP can leverage the presence of the MISO energy

[20] Minnesota Power Responses to MCEA Informal Questions on 2010 IRP. Email from Julie Pierce, August 6, 2010.

market and MISO regional transmission tariff to procure the most economical levels of wind energy available.

Additional transmission is currently being built in the MISO region, with plans for future transmission additions that will help integrate wind generation into the region. Table 4 compares the MP Reference Case to a revised Reference Case where the imposed limits on wind additions have been removed.

Table 5. Comparison of Resource Additions in the MP Reference Case and a Reference Case that Allows for Increased Wind Generation.

	Reference	Increased Limit on Wind Units
2010	Manitoba Surplus Energy Purchase 13 MW Conservation	Manitoba Surplus Energy Purchase 13 MW Conservation
2011	**[TRADE SECRET MATERIAL BEGINS**	
		TRADE SECRET MATERIAL ENDS]
2009 NPV	**$3.81 B**	**$3.79 B**

Table 4 shows that when the constraints are removed, Strategist selects a total of **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** of wind additions between 2015 and 2017, and does so at an NPV that is less than that of the MP Reference Case.

2. *Wind Capital Costs Assumption*

A 2008 map of wind potential from the National Renewable Energy Laboratory (NREL)[21] shows that the wind potential for North Dakota, with tower hub heights at 50 meters, most of the state is made up of Class 3 to Class 5 wind sites, where wind speeds range from 6.4 to 8.0 meters/second. Also, more recent estimates for wind potential in North Dakota by NREL[22] show that at 80 meter hub heights, wind class regimes upwards of Class 6 abound in North Dakota, one of the top states in the nation for wind resource

[21] Available at: http://www.nrel.gov/gis/images/map_wind_national_lo-res.jpg
[22] Available at: http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=nd.

potential. There are areas of northeastern Minnesota with very little wind resource potential, but at a height of 50 meters, much of the northwestern and southern parts of the state are made up of Class 3 sites, with some Class 4 and 5 sites. At 80 meter hub heights, there are some sites in the southwestern corner of Minnesota that become Class 6 sites.

MP determined capital costs for future wind installations by scaling costs of MP's Bison I wind farm, at 79.5 MW, to wind farms of 100 MW. MP then applied an escalation rate of **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** per year to those capital costs. While capital costs for wind power had been on the rise through 2009, various sources predict that real capital costs will actually fall over the long-term due to supply market maturity and ongoing technological gains, such as, but not limited to, improved economies of scale and greater performance of wind turbines at higher hub heights.

Engineering firm Black & Veatch is one such source, predicting that capital costs for wind will fall in the coming years. These predictions of future wind costs, by Resource Class and Year, are shown in Table 6. Black & Veatch costs are shown in real 2006 dollars, and in addition to inflation, the installed costs for wind generation have increased since the study was performed due to rising costs of turbine components. The intent in showing this table is to illustrate, however, *long-term trends* in the installed cost of wind power, rather than comparing capital costs shown here to those used by MP in its modeling.

Table 6. Onshore Wind Costs and Performance (2006$).[23]

Resource Class	Install Year	Capacity Factor (%)	Capital Cost ($/kW)	O&M ($/kW-yr)	O&M ($/MWh)	Costs w/o PTC ($/MWh)	Costs w/ PTC ($/MWh)
3	2005	32	1650	11.5	7.0	$94	$71
3	2010	35	1650	11.5	5.5	$86	$63
3	2015	36	1609	11.5	5.0	$80	$57
3	2020	38	1568	11.5	4.6	$76	$53
3	2030	38	1485	11.5	4.4	$70	$47
4	2005	36	1650	11.5	7.0	$85	$62
4	2010	39	1650	11.5	5.5	$77	$54
4	2015	41	1609	11.5	5.0	$72	$49
4	2020	42	1568	11.5	4.6	$68	$45
4	2030	43	1485	11.5	4.4	$64	$41
5	2005	40	1650	11.5	7.0	$78	$55
5	2010	43	1650	11.5	5.5	$71	$48
5	2015	44	1609	11.5	5.0	$67	$44
5	2020	45	1568	11.5	4.6	$64	$41
5	2030	46	1485	11.5	4.4	$60	$37
6	2005	44	1650	11.5	7.0	$72	$49

[23] Black & Veatch. *20 Percent Wind Penetration in the United States: A Technical Analysis of the Energy Resource*. October 2007. page 5-4.

6	2010	46	1650	11.5	5.5	$67	$44
6	2015	47	1609	11.5	5.0	$63	$40
6	2020	48	1568	11.5	4.6	$60	$37
6	2030	49	1485	11.5	4.4	$57	$34
7	2005	47	1650	11.5	7.0	$67	$44
7	2010	50	1650	11.5	5.5	$62	$39
7	2015	51	1609	11.5	5.0	$59	$36
7	2020	52	1568	11.5	4.6	$56	$33
7	2030	53	1485	11.5	4.4	$53	$30

Black & Veatch states that "it is possible that real costs decline roughly 10 percent over the next 25 years" with increased US-based manufacturing, increased efficiencies in manufacturing, and new technologies and materials that allow for greater turbine scale.[24] Given these predictions of falling capital costs for wind technologies, MP's inclusion of a **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** escalation rate for wind capital costs may overstate those costs.

More recently, the US DOE has stated that

> Installed costs (for wind) may – on average – remain high for a period of time as developers continue to work their way through the dwindling backlog of turbines purchased in early 2008 at peak prices. There are expectations, however, that average costs will decline over time as the cost pressures (e.g., rising materials costs, the weak dollar, turbine and component shortages) that have challenged the industry in recent years ease.[25]

Increases in installed costs has mirrored the trend of increasing turbine prices, indicating that rising turbine prices is the most significant contributor to installed costs. Turbine price increases have been the result of many factors, including:

- A decline in the value of the dollar relative to the Euro
- Increased materials prices
- Increased input energy prices (i.e. steel and oil)
- Actions by manufacturers intended to increase profitability
- Shortages in specific turbine components
- An increase in turbine size and hub height; and
- A greater sophistication in turbine design[26]

Data collected by DOE on wind turbine transaction prices indicates that prices may already be starting to decline, as shown in Figure 2.

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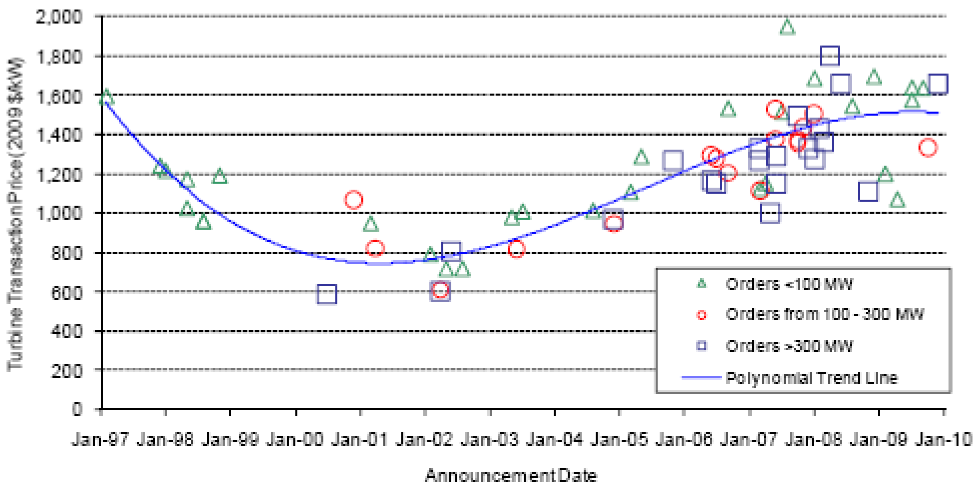
[24] Black & Veatch. *20 Percent Wind Penetration in the United States: A Technical Analysis of the Energy Resource*. October 2007. page 5-6.
[25] US Department of Energy. *2009 Wind Technologies Market Report*. August 2010. page vi – vii.
[26] US Department of Energy. *2009 Wind Technologies Market Report*. August 2010. page 47.



Source: Berkeley Lab

Figure 4. Wind Turbine Transaction Prices Over Time in the United States.[27]

According to DOE, the on-going financial crisis has been largely responsible for these declines in wind turbine transaction prices, as the turbine supply is greater than the near-term wind development plans. Investment bank UBS has estimated that average turbine sales prices declined by 13% in 2009.[28] Bloomberg New Energy Finance looks to the future, estimating that turbines sold in the second half of 2010 will cost 15% less than those turbines sold in the second half of 2008.[29] Because declines in turbine prices lead to declines in the installed costs for wind generation, total wind project costs and wind power prices can be expected to fall over time.

Finally, adjustments to the O&M costs for existing thermal resources and proper consideration of the costs of future environmental regulations makes wind costs much lower by comparison.

D. MP's Modeling Omits Significant Existing O&M Costs for MP's Coal Fleet.

Minnesota Power greatly understates the non-fuel O&M costs (both fixed and variable) for its existing coal-fired power plants. This will tend to overstate any economic benefits of continued operation of these plants. Or alternatively, it will tend to cause the Strategist model to underestimate the benefits of closing these plants.

Table 6, below, lists actual and projected annual non-fuel O&M costs for the Boswell, Laskin Energy, Taconite Harbor, and Hibbard plants.[30] The actual data for 2005 to 2009

[27] US Department of Energy. *2009 Wind Technologies Market Report*. August 2010. page 48.
[28] UBS Limited. *UBS Global I/O: Global Wind Sector*. UBS Investment Research. March 15, 2010. As cited in: US Department of Energy. *2009 Wind Technologies Market Report*. August 2010. page 48.
[29] Bloomberg New Energy Finance. *Q1 Wind Market Outlook*. February 2010. As cited in: US Department of Energy. *2009 Wind Technologies Market Report*. August 2010. page 48.
[30] The data shown for the Hibbard Plan is for units 3 & 4 only; it does not include the biomass expansion at Hibbard that begins generating in 2013.

are from MN Power's FERC Form No. 1 filings, which sum the fixed and variable components of the reported non-fuel O&M costs. The cost projections for 2010–2025 are from the Strategist model outputs for the Company's Reference Case in this case. The actual costs for Boswell, Laskin Energy, Taconite, and Hibbard for 2009 are $34 million, $6.5 million, $9.4 million, and $3.6 million, respectively. These are reasonably typical of the five-year actual period. The projections MP models for O&M costs for 2010, however, are only a small fraction of the units' 2009 actual costs, that is, **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** of the 2009 actual O&M costs for the four plants. After 2010, MP's projected O&M costs for Boswell, Laskin, and Taconite Harbor rise at an annual inflation rate of **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** through the 15 year modeling period.

Table 7. Comparison of Historical and Projected Fixed and Variable O&M Costs.

	Boswell 1-4			Laskin Energy 1-2			Taconite Harbor 1-3			Hibbard 3-4		
Year	**K$**	**GWh**	**$/MWh**	**K$**	**GWh**	**$/MWh**	**K$**	**GWh**	**$/MWh**	**K$**	**GWh**	**$/MWh**
2005	$28,646	6,450	$4.44	$6,202	696	$8.92	N/A	N/A	N/A	$3,869	76	$50.82
2006	$28,033	6,381	$4.39	$7,459	624	$11.95	$8,241	1,467	$5.62	$4,395	80	$55.12
2007	$32,210	6,006	$5.36	$7,442	591	$12.58	$10,453	1,491	$7.01	$3,338	53	$62.57
2008	$29,045	6,365	$4.56	$6,608	659	$10.02	$11,736	1,473	$7.97	$3,874	62	$62.85
2009	$34,027	5,390	$6.31	$6,515	511	$12.76	$9,365	1,058	$8.85	$3,583	41	$88.02
[TRADE SECRET MATERIAL BEGINS												

TRADE SECRET MATERIAL ENDS]

The disparity between MP's actual O&M costs from 2005-2009 and its projected O&M costs illustrates several important errors with the Company's modeling of O&M in Strategist: (1) fixed O&M costs are omitted entirely; (2) variable O&M costs are underestimated; and (3) escalation of O&M costs is underestimated. We will discuss each of these errors, starting with the omission of fixed O&M.

Power plant O&M costs are commonly considered to fall into two categories, fixed and variable. Fixed O&M includes costs that do not scale with the amount of output from the plant. These are generally expressed in $ per kW of capacity. Variable O&M includes the costs that do scale with the amount of generation. These are commonly expressed in units of $ per MWh.

MP's Strategist model inputs **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** for all of the fixed O&M costs for these thermal generating units. This is a significant oversight, since fixed O&M generally represents about half of total O&M. This omission explains a large portion of the O&M cost discontinuity between actual and projected that can be observed in Table 7. It is a problem for the IRP modeling, because without fixed O&M included, any projections of total system costs will be incomplete, and if MP were to carry out any analysis of retirement of existing capacity based on such data, it would be biased.

Second, even in terms of just the variable portion of O&M, the cost inputs in Strategist appear to be unrealistically low. Variable O&M might typically be in the ballpark of one half of the total O&M, but the comparison in Table 7 shows that the 2010-2025 inputs are **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** of MP's historical O&M. In order to provide an accurate simulation of the dispatching of Minnesota Power's generating units it is important to have reasonable inputs for variable O&M.

Third, the O&M inputs to Strategist escalate at just **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** over the fifteen-year model period. This resembles the general rate of price inflation in the economy, and appears to reflect MP's "duty cycle preservation" approach to capital investment and maintenance expenditures, discussed in Part 1 of Appendix C to the IRP. For these power plants, however, there are reasons to expect that O&M cost increases will be significantly higher. As discussed in the earlier section of these comments, environmental regulatory compliance (and associated capital investments) may drive up O&M costs at MP's existing fossil plants. For example, SCR for NO_x controls and FGD for SO_2 control can add $8/MWh and $15/MWh to plant O&M costs, respectively (based on EPA's 2010 IPM input data assumptions).[31]

MP's Strategist model runs are inaccurate in that they ignore fixed O&M, underestimate variable O&M, and do not recognize real escalation of O&M costs in the future.

IV. SYNAPSE'S STRATEGIST MODELING DEMONSTRATES THAT MP COAL UNIT RETIREMENTS HAVE ECONOMICAND OTHER PUBLIC INTEREST BENEFITS.

Synapse Energy Economics modeled a variety of unit retirement sensitivity cases using the inputs from MP's Reference Case. None of MP's input assumptions were changed in any of the retirement scenarios modeled. The only change made was to retire the units in

[31] ICF International. *EEI Preliminary Reference Case and Scenario Results*. May 21, 2010. Slide 32.

pairs at the end of 2012, the year in which emissions reductions begin to be required by the Air Transport Rule. The 2009 NPV of each of these scenarios along with the resource additions selected by Strategist are shown in Table 8, along with MP's Reference Case for comparison purposes.

In the three scenarios in which unit pairs are retired – Boswell 1 & 2, Laskin 1 & 2, and Taconite 1 & 2 – Strategist shifts the addition of wind resources forward in time. Once the model reaches the cumulative maximum for wind additions, it must start adding market purchases in order to maintain the required reserve margin. The scenario that retires Taconite 3 as a single unit keeps the same schedule for wind as in the MP Reference Case, but the model must again add market purchases between 2016 and 2019 for reserve margin purposes.

As illustrated by Table 8, some of MPs units appear to be uneconomic even when using the Company's flawed and incomplete Reference Case assumptions, and there may be cost benefits to unit retirement.

Table 8. MP Reference Case as Compared to Various Retirement Scenarios.

	Reference	Retire Boswell 1 & 2	Retire Laskin 1 & 2	Retire Taconite 1 & 2	Retire Taconite 3
2010	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation
2011	**[TRADE SECRET MATERIAL BEGINS**				
					TRADE SECRET MATERIAL ENDS]
2009 NPV	**$3.81 B**	**$3.86 B**	**$3.79 B**	**$3.80 B**	**$3.82 B**
Difference from Reference Case	**N/A**	**$ + 0.05 B**	**$ - 0.02 B**	**$ - 0.01 B**	**$ + 0.01 B**

Synapse also created a "Synapse Reference Case" which incorporates some of the recommendations made earlier in these Comments. Specifically, the Synapse Reference Case (SRC):

1. raises the wind limitation to an incremental maximum of 500 MW per year and the cumulative maximum of 1,000 MW over the course of the planning period; and
2. increased fixed and variable O&M costs for MN Power's thermal units based on historical costs given in FERC Form 1 documents

The SRC *does not* add any capital costs associated with upcoming environmental regulations, or any emissions allowance prices that are not already included in MP's Reference Case, i.e. capital costs for emission control technologies or costs of emissions allowances for SO_2 and NO_x. It also *does not* include any additional capital costs for any thermal units, including standard maintenance or replacement costs for things like boiler tubes or economizers that could accelerate as a generation unit ages. It also *does not* remove the escalation from the capital costs for wind generation. The SRC and its various sensitivity scenarios can thus be considered a conservative set of Model runs and associated outputs, as it would be realistic to assume that there will be some future costs associated with routine unit upgrades and future environmental controls.

Synapse also used its Reference Case to model several retirement scenarios. Units were taken in pairs, and Synapse selected those units that had lower nameplate capacities paired with high emissions rates of NO_x and SO_2, believing those to be the most likely candidates for retirement based on age and emission rates. Units were retired in the model at the end of 2012, which is the first year in which emissions reductions are required under the Transport Rule. Those results are shown in Table 9, below.

When looking at the output from the SRC modeling run, the two changes made to the input assumptions become obvious right away. Rather than selecting only **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** of wind, as in the MP Reference Case, the model chooses to add **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** of wind in total over the planning period, and **[TRADE SECRET MATERIAL BEGINS TRADE SECRET MATERIAL ENDS]** of wind in 2015 alone. This is not surprising; as the results from the Model run that simply increases the limits for wind (keeping all other MP assumptions the same) shows that Strategist chooses more wind at a lower NPV (see Table 5). In the SRC, the Model adds those wind units at a faster rate, driven by the effect of the second input assumption change that was made in the SRC – the increased fixed and variable O&M costs for MP's thermal units.

The resulting NPV of the Synapse Reference Case was approximately $4.17 billion. Given that Strategist added more wind units at a lower cost when the limitations on wind were increased, this resulting NPV could be driven in part by the fact that the wind units in the SRC come online earlier in the planning period, but the primary factor in the increased cost of the plan is the increased fixed and variable O&M for MP's thermal units.[32] And these increased operating costs for thermal units make retirement scenarios look even more attractive in this set of sensitivity runs.

[32] The resulting NPV in the scenario that simply removes the wind limitation is approximately $3.79 billion (see Table 5), while the NPV of the Synapse Reference Case is approximately $4.17 billion. Modeling results show that approximately $342,000 is due to the addition of another 100 MW of wind in 2015, and the remaining $380 million is due to the increased O&M.

Table 9. Synapse Reference Case Scenario and Various Retirement Scenarios.

	Synapse Reference	Retire Boswell 1 & 2	Retire Laskin 1 & 2	Retire Taconite 1 & 2	Retire Taconite 3
2010	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation	Manitoba Energy Purchase 13 MW Conservation
2011	[TRADE SECRET MATERIAL BEGINS				
					TRADE SECRET MATERIAL ENDS]
2009 NPV	**$4.17 B**	**$4.17 B**	**$4.10 B**	**$4.10 B**	**$4.15 B**
Difference from Reference Case	**N/A**	**$ 0.0 B**	**$ - 0.07 B**	**$ - 0.07 B**	**$ - 0.02 B**

The retirement scenarios that use MP's input assumptions (shown in Table 8) show mixed results. The scenarios retiring Boswell 1 & 2 and Taconite 3 are slightly more expensive than the Reference Case, while the scenarios that retire Laskin 1 & 2 and Taconite 1 & 2 are slightly less expensive than the Reference Case. When performing Model runs with more appropriate O&M costs, as in the SRC and the associated runs, all of the retirement scenarios modeled look at least as attractive, if not more attractive, than the Reference Case on a strict cost basis, while meeting all reliability requirements.

It is interesting to note that in the Synapse Model runs, Strategist begins to select Conservation Alternative 3 in many of the alternate plans shown in the Model output. Increased operating costs for thermal units, then, makes this conservation option a more attractive resource choice. Establishing and modeling various incremental amounts of energy efficiency and demand response becomes even more important when assuming increased costs for thermal units.

The resulting NPV of the Synapse Reference Case was approximately $4.17 billion, and all of the retirement scenarios modeled had an NPV that was equivalent to or less than the SRC. Modeling results from sensitivities performed using MP assumptions as well as from the SRC and associated retirement scenarios indicates that MP's modeling results and subsequent IRP are biased in favor of the continued operation of all of the Company's thermal units. It is imprudent for MP to go forward with resource planning without reexamining its input assumptions and analyzing a variety of retirement scenarios.

Xcel Energy, a utility with operations in Minnesota and several other states, was required in Colorado to file an emissions reductions plan with the State under the recently enacted Clean Air-Clean Jobs Act (CACJA), as a framework for responding to upcoming Clean Air Act and other environmental requirements. The legislation requires that Xcel (operating as Public Service Company of Colorado) look at a variety of emission reductions scenarios that include the retrofit of existing units with emission control technologies as well as retirement scenarios for coal units.

After examining several scenarios, the final Plan proposed by the Company includes the retirement of 903 MW of coal-fired capacity over the planning period (2010- 2024), to be replaced with combined-cycle gas generation. Early in the planning period, Xcel plans to retire its Cherokee 2 unit (106 MW) as a coal unit after the summer peak in 2011 and also plans to retire the Cherokee 1 unit (107 MW) in late 2011 or early 2012. The decision to retire these units was based in part on the age of the units (53 years for Cherokee 1 and 51 years for Cherokee 2) and that the retirement of these units "makes the most sense from a cost and an emissions reductions perspective."[33]

MP's Boswell 1 & 2 units are comparable in age to Xcel's Cherokee 1 & 2 units, and the Laskin and Taconite units are slightly older (with the exception of Taconite 3). All of the units are also at least 25 MW smaller than the Cherokee units. These two factors make

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[33] Public Service Company of Colorado. *Clean Air-Clean Jobs Act Emissions Reduction Plan*. CPUC Docket No. 10M-245E. August 13, 2010. page 10.

MP's units appear to be favorable candidates for retirement. Xcel's final Plan demonstrates that it is possible to retire coal-fired capacity as early as 2012.

V. RECOMMENDATIONS AND CONCLUSIONS

When examining the results of MP's Strategist modeling analysis, it is clear that there are some scenarios under MP's Reference Case in which the retirement of coal-fired units would be the most economic alternative. *Even when none of MP's input assumptions are modified*, the modeling outputs set forth in Table 8 show NPVs that are lower than the Reference Case value of $3.81 billion in the scenarios that retire Laskin 1 & 2, or Taconite 1 & 2; scenarios retiring Boswell 1 & 2 and Taconite 3 look only slightly more costly than MP's Reference Case. Yet MP failed to examine such scenarios in its IRP and presented a plan that is biased toward the continuing operation of its existing thermal units regardless of the economics of doing so.

The economic benefits of retirement of one or more of MP's coal-fired units are even greater when some of the Company's flawed input assumptions are adjusted to be more reasonable. In its own modeling analysis, Synapse Energy Economics increased MP's modeling limitation on wind units. Synapse also increased the fixed and variable O&M costs of MP's coal units to be in line with the historical operating costs experienced at these units. No other input assumptions were changed, and no additional costs were added to coal units.

The resulting Synapse Reference Case has a NPV of $4.17 billion, showing that the MP Reference Case underestimated costs by at least a third of a billion dollars. All of the retirement scenarios look better than the corrected reference case by comparison. The scenario retiring Boswell 1 & 2 is approximately equivalent to the MP Reference Case, retiring Taconite 3 would be $20 million less than the MP Reference Case, and retiring Laskin 1 & 2 or Taconite 1 & 2 would be $70 million less. These Synapse model runs can be considered conservative adjustments to the resulting NPVs, because they do not add any capital costs associated with routine unit upgrades or installed emissions controls, nor do they add any additional operating costs associated with upgrades or controls. If and when these additional costs are added to the input assumptions used in the modeling, retirement scenarios will look that much more economic.

We recommend that MP revise its resource planning assumptions as follows:

a. MP should do a DSM potential study for its service territory;

b. Based on the results of this study, MP should analyze smaller increments of additional energy conservation, above the 1.8% it has historically achieved and that was consistently selected by the Model, in order to determine the maximum amount of cumulative energy conservation savings that is a cost-effective option;

c. Again using the results of the DSM study, MP should also examine the potential for greater demand response savings from its large industrial customers;

d. MP should increase or remove its modeling limitations for wind and reexamine its assumptions about capital costs for wind generation resources;

e. Fixed O&M costs need to be taken into consideration and included as Strategist inputs;

f. Variable O&M needs to be adjusted upward to conform to the Company's historical costs for the existing fleet;

g. MP needs to do a thorough analysis of forthcoming environmental regulations and the effect on its generation mix, which includes an analysis of applicable emissions control technologies and their associated costs.

And finally, MP should model a variety of retirement scenarios using the updated input assumptions. Requiring MP to study retirement alternatives for the Company's next IRP filing, especially if that filing is not due until 2012, would likely not result in any unit retirements before 2014. One example has already been given earlier in these comments of a utility that is making plans to retire coal-fired generation as early as the summer of 2011. Synapse modeling efforts, even using all of MP's input assumptions, shows that retirement of MP coal units by 2012 would result in economic benefits. MP, therefore, should be directed to examine retirement scenarios as soon as is feasible, not to wait until its next regularly-filed resource plan.

Utilities and merchant generators around the country will likely be retiring coal-fired generating units in the near future. Two recent studies suggest that between 25 and 40 GW of coal capacity will retire between now and 2015,[34] as a result of low energy prices and forthcoming air regulations from the EPA. The bulk of the units likely to retire are lacking emissions controls, are less than 250 MW in size, and are between 40 and 60 years old.[35] Synapse's Strategist analysis presented in these comments shows that MP would be able economically to retire one or more of its coal units, and do so without negatively impacting reliability in its service territory, as the required reserve margin is maintained in all years. Recent actual reserve margins in the Midwest Reliability Organization (MRO) have been well above minimum levels, and the North American Electric Reliability Corporation (NERC) estimates that the reserve margin in MRO is 2013 will be 22.1%, which is 3.2 GW above the target.[36]

Unit retirement has many other benefits, in addition to the economic benefits shown in the Synapse modeling analysis. Retiring units would avoid emissions of SO_2 and NO_x, which currently carry an allowance price, and CO_2, which is expected to have an

[34] See: ICF International. *EEI Preliminary Reference Case and Scenario Results*. May 21, 2010. See also: PIRA Energy Group. *EPA's Upcoming MACT; Strict Non-Hg Can Have Far-Reaching Market Impacts*. April 8, 2010.
[35] MJ Bradley and Associates and Analysis Group. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*. August 2010. Page 19.
[36] NERC. *2009 Long-Term Reliability Assessment: 2009-2018*. October 2009.

allowance price in the near term. Reducing emissions of these pollutants would allow MP to sell its extra allowances to other generators, resulting in added economic benefits. Decreased emissions also avoid health and damage externalities associated with these pollutants. Finally, the retirement of existing capacity creates space on the transmission grid to accommodate additional power flows, such as from new wind units, without requiring upgrades to the system.

In conclusion, retirement of one or more of MP's coal units is economically feasible, has associated with it a number of other benefits that are in the public interest, and should be examined as soon as possible.

Date: September 27, 2010

Respectfully submitted by,

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