Synapse
Energy Economics, Inc.

Comments on Wolverine Power Cooperative's *Electric Generation Alternatives Analysis* for the Proposed Rogers City Coal Plant

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SUMMARY OF COMMENTS

1. Our review has been severely handicapped by Wolverine's failure to include workpapers and supporting data with the Electric Generation Alternatives Analysis (EGAA) and by the very short 30 day period we have had to review the Wolverine EGAA and prepare these comments.

2. The least cost planning analyses presented in the EGAA only considered natural gas and coal options. They did not reflect any wind or other renewable resources, any additional energy efficiency or purchases of energy from existing natural gas-fired plants that could be included as parts of portfolios of alternatives to the proposed Rogers City project.

3. Wolverine's use of a low construction cost for a new coal-fired power plant biases its cost analyses in favor of the coal alternatives.

4. Wolverine biased the least cost planning analyses in favor of the baseload coal option by assuming an unreasonably low heat rate.

5. A comprehensive system for federal regulation of carbon dioxide (CO_2) and other greenhouse gas emissions is inevitable, and it is generally expected that steep emissions reductions will be required. Consequently, all of Wolverine's planning analyses and cost comparisons that do not include a cost for CO_2 emissions should not be considered. This includes most of the least cost planning analyses presented in the EGAA as well as the alternatives cost comparisons presented in Table 6.4 and Figure 6.6.

6. If it operates at an average annual 85 percent capacity factor, the Rogers City CFB plant will emit more than 4.5 million tons of CO_2 each year. Wolverine has not properly considered the costs of these emissions in its costs analyses.

7. The inevitable regulation of greenhouse gas emissions by the federal government will require the State of Michigan to reduce its current heavy dependence on coal-fired power plants.

8. Wolverine's assumption of a very high natural gas price in its Carbon Tax Scenario biases its cost analyses in favor of the coal alternative.

9. There is no evidence to support Wolverine's claim that carbon regulation would increase the price of natural gas by 25 percent or more.

10. Wolverine's analyses are biased against new wind facilities by the failure to include a wind capacity credit.

11. Wolverine unreasonably assumes that its members will not be able to achieve more than 0.2 percent annual incremental energy efficiency savings after the year 2015.

12. The EGAA ignores the availability of a substantial amount of under-utilized gas-fired combined cycle and gas turbine capacity that could provide much, if not all,

of the energy that would be generated at the proposed Rogers City CFB coal plant.

13. Uncertainty over construction costs and the costs of complying with future federal carbon dioxide emission reduction requirements have, in significant part, led to more than 90 coal power plant cancellations, delays and rejections by state regulatory commissions.

COMMENTS

1. Our review has been severely handicapped by Wolverine's failure to include workpapers and supporting data with the Electric Generation Alternatives Analysis (EGAA) and by the very short 30 day period we have had to review the Wolverine EGAA and prepare these comments.

Wolverine has provided only a very few of the detailed assumptions that it used in its least cost planning analyses, particularly its comparison of the levelized busbar costs of the Rogers City CFB plant and its lower emitting alternatives. It has provided none of the calculations, workpapers or computer files used in these analyses. Thus, it is impossible to verify the claims made by Wolverine in the Electric Generation Alternatives Analysis (EGAA). This is particularly true of the cost comparisons between the proposed Rogers City project and the lower emitting technologies presented in Table 6.4 and Figure 6.6 of the EGAA.

Wolverine also has failed to provide the detailed assumptions, calculations, workpapers or computer files that underlay other claims made in the EGAA in areas such as projected load growth, power plant emissions, and assumed CO_2 prices. Thus, it is also impossible to verify the claims made by Wolverine in these areas of the EGAA.

2. The least cost planning analyses presented in the EGAA only considered natural gas and coal options. They did not reflect any wind or other renewable resources, any additional energy efficiency or purchases of energy from existing natural gas-fired plants that could be included as parts of portfolios of alternatives to the proposed Rogers City project.

Wolverine limited the options in its least cost planning analyses to gas for peaking and intermediate resources and coal for baseload resources. This was an unreasonable limitation. Other resources can operate as baseload facilities – for example, a biomass burning facility or wind facilities in conjunction with natural gas. It is now widely recognized that wind can be an important part of a portfolio of resources that can provide needed capacity and baseload energy, and when combined with other energy resources, wind can produce electricity in patterns comparable to a baseload generating facility. Increased energy efficiency expenditures also can lead to savings in both peak loads and energy requirements. Demand response also can assist in reducing peak loads. A vigorous resource plan including these elements and solar can and should be implemented.

Unfortunately, Wolverine relies on spread sheet analyses instead of the state of the art capacity expansion and production simulation models used for resource planning by the overwhelming majority of other utilities, including G&T cooperatives, around the nation.

This limits Wolverine's ability to develop a plan that optimizes the timing and types of resource additions to produce a low cost, low risk plan.[1] The screening curves presented by Wolverine in its EGAA are just that, screening curves that could be one step in the planning process, but not the final basis on which selections of the optimal timing and mix of supply- and demand-side resources are made.

Wolverine's failure to consider energy efficiency and renewable alternatives in its least cost planning analyses leaves it with an inflexible resource plan that would be imprudently dependent upon a single fossil-fired plant, that is, the Rogers City project. In fact, the Rogers City project's 600 MW of output and 4.5 million MWh of generation (assuming an 85 percent capacity factor) would represent approximately 76 percent of Wolverine's base case peak demand in 2021 and more than 100 percent of its base case energy requirements.[2] Such a heavy dependence on fossil-fired generation would be unreasonably risky given the inevitable federal regulation of greenhouse gas emissions and other financial and construction cost uncertainties. A dependence upon a single fossil-fired generating unit would be even riskier for Wolverine's members and their customers.

In contrast to the heavy dependence on fossil-fired generation, Wolverine's proposed resource plan with the Rogers City project would include only a very small amount of energy efficiency. For example, Wolverine's Answers to MPSC Staff Question No. 7 from June 15, 2009 indicates that energy efficiency would only represent 5 percent of Wolverine's resource mix in 2021 based on MWh and only 3 percent of its resource mix based on MW.[3] It is unclear from the information provided by Wolverine what portion of its future resource mix after 2015 would be from renewable resources.

The emphasis in its EGAA on the statewide and regional need for new generating facilities suggests that Wolverine, at least in part, wants to build the proposed Rogers City project to meet future off-system loads. This is a risky strategy.

The example of the Vermont Electric Cooperative ("VEC") represents the danger that overbuilding to meet prospective off-system loads can pose. In the 1970s, VEC borrowed funds to invest in a number of proposed power plants as part of a conscious attempt to participate in a number of proposed baseload facilities much larger than would be needed to serve its own loads. Instead, VEC planned to use some of the capacity from these facilities to make off-system sales to other cooperatives and to private utilities in the

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1 For example, it might be that additional energy efficiency expenditures between 2009 and 2015 would produce savings in excess of those required by Michigan Public Act 295. However, the additional savings from these expenditures might significantly delay the need for expensive new baseload capacity and energy. However, Wolverine is unable to evaluate alternatives such as this because it does not use industry standard capacity expansion modeling techniques.

2 These percentages are calculated by dividing the Wolverine Composite Long-Range Load Forecast figures in Table 2.7 of the EGAA by the unit's 600 MW net output and 4.5 million MWh expected annual generation.

3 This same answer also indicates that Wolverine only expects to achieve extremely minor incremental peak demand reductions after 2015, increasing from 22 MW through 2015 to only 26 MW through 2021.

northeast. However, the costs to build the plants rose significantly and the projected loads did not materialize. As a result, VEC entered bankruptcy in the mid 1990s.[4]

Through our work analyzing utility resource planning, Synapse has identified a set of good, or "prudent," electric resource planning practices:

- Actively seek out relevant information.
- Rely on up-to-date and realistic construction cost estimates.
- Include reasonable CO_2 price forecasts in the reference case, and analyze high and low sensitivities.
- Include full consideration of alternatives.

We also have identified a set of poor, or "imprudent," planning practices:

- Passive attitude toward information.
- Rely on out-of-date construction cost estimates.
- Ignore CO_2 price, look at a single, low set of CO_2 prices, or treat CO_2 "at the end" as a sensitivity case.
- Overly constrain alternatives such as renewable resources and energy efficiency.
- Claim that a proposed coal plant is part of a strategy or plan for reducing CO_2 emissions.

Unfortunately, from what we have seen in the EGAA it appears that Wolverine's planning practices are poor or imprudent and do not reflect typical industry practices.[5] This increases the risks for Wolverine's members and their customers.

3. Wolverine's use of a low construction cost for a new coal-fired power plant biases its cost analyses in favor of the coal alternatives.

Wolverine is inconsistent as to what the $2,200 per kW estimated cost for a new baseload circulating fluid bed ("CFB") coal plant actually represents. In the EGAA, this $2,200 per kW figure is said to be an installed cost.[6] This suggests that it includes escalation and perhaps Allowance for Funds Used During Construction ("AFUDC") as well. However, during the technical forum Wolverine indicated, after some hesitancy, that the $2,200 per kW figure was an "overnight" cost which suggests that it does not include escalation or AFUDC. Either way, Wolverine's estimated cost for the proposed Rogers City project is significantly lower than the costs of other recently proposed CFB plants and Consumers

[4] Prefiled Testimony of William Steinhurst on behalf of the Vermont Department of Public Service, Vermont Public Service Board Docket Nos. 5630 and 5632, July 6, 1993, at page 21.

[5] For example, Wolverine's use of an excel spreadsheet model instead of the capacity expansion models typically used by both investor-owned, public utilities and cooperatives.

[6] EGAA, Table 4.6, at page 52 of 114.

Energy's recent estimate of what it would cost that Company to build a new CFB coal plant.

In fact, coal power plant construction costs have risen dramatically since the early years of this decade as a result of a worldwide competition for design and construction resources, equipment, and commodities like concrete, steel, copper and nickel. As a result, coal-fired power plants that were estimated to cost $1,500 per kilowatt in 2002 are now projected to cost in excess of $3,500 per kilowatt.

Significant cost increases have been announced in recent years for many other proposed coal-fired power plants. For example, the estimated per unit construction cost of Duke Energy Carolina's Cliffside Project increased by 80 percent between the summer of 2006 and June 2007. Similarly, the projected construction cost of Wisconsin Power & Light's now-cancelled Nelson Dewey 3 coal plant increased by approximately 47 percent between February 2006 and September 2008. The estimated cost of AMP-Ohio's proposed Meigs County Coal Plant nearly tripled in the three years between October 2005 and October 2008. Similarly, the estimated construction cost of the Karn-Weadock advanced supercritical pulverized coal plant, proposed by Consumers Energy in Michigan, has increased from $2,765 per kW in 2007 to $3,589 per kW in January 2009, a 32 percent increase.[7]

As shown in Figure Synapse-1 and Table Synapse-1 below, Wolverine's estimated cost for its proposed Rogers City project is significantly lower than recent cost estimates for other proposed coal plants.

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[7] The new cost estimate was presented to the Commission in Case No. U-15800 in a January 15, 2009 report from HDR/Cummins & Bernard, at page 12.

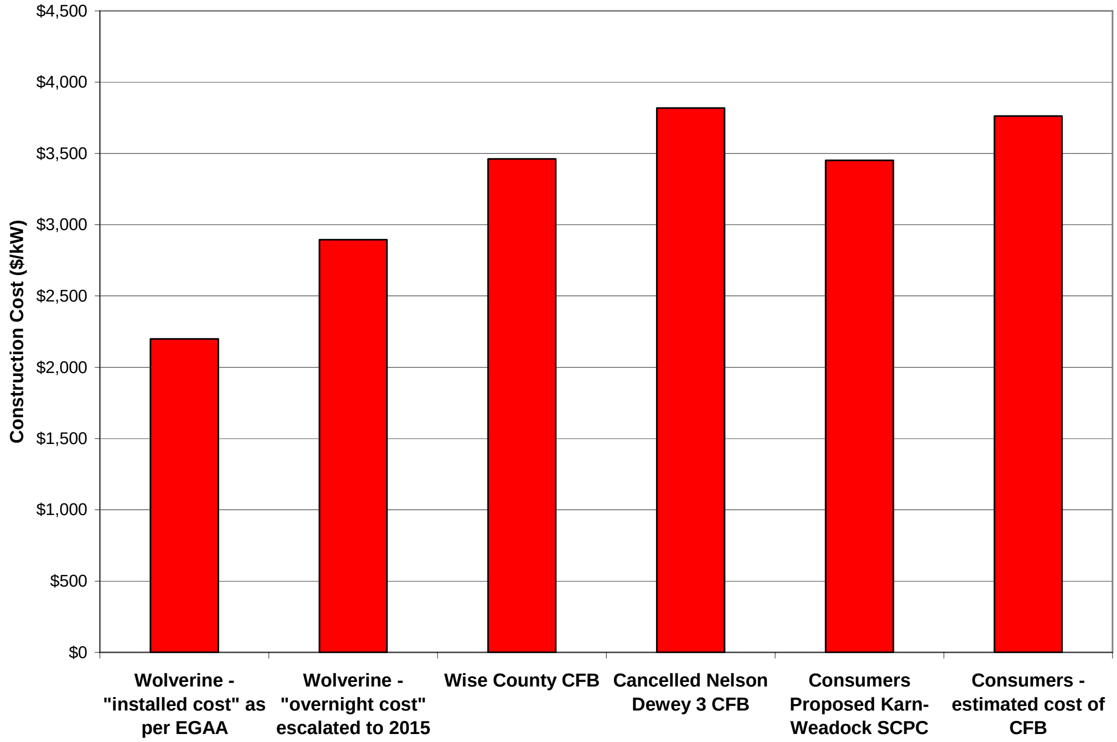

Figure Synapse-1: **Cost Estimates for Wolverine's Proposed Rogers City Coal Plant vs. Cost Estimates for Other CFB Coal Plants and Coal Plants Proposed for Michigan.**

Plant	Estimated Cost without AFUDC ($/kW)
Wolverine - "installed cost" as per EGAA	$2,200
Wolverine - "overnight cost" escalated to 2015	$2,895
Wise County CFB	$3,461
Cancelled Nelson Dewey 3 CFB	$3,818
Consumers Proposed Karn-Weadock SCPC	$3,451
Consumers - estimated cost of CFB	$3,762

Table Synapse-1: **Cost Estimates for Wolverine's Proposed Rogers City Coal Plant vs. Cost Estimates for Other CFB Coal Plants and Coal Plants Proposed for Michigan.**

Thus, the conclusion is the same whether you assume that the $2,200 per kW construction cost presented in the EGAA is an "installed cost" or an "overnight cost:" the estimated coal cost that Wolverine used in the economic analyses in the EGAA is much lower than the costs of other recently estimated CFBs, and is lower than the cost estimate for Consumers Energy's proposed Karn-Weadock plant. Based on these other estimates, it would have been more reasonable for Wolverine to use a CFB coal plant cost of $3,500 per kW to $3,800 per kW in its economic analyses.

Wolverine has claimed that there are a number of site-specific factors that would reduce the construction cost of its proposed CFB but these claims are simply not credible. The main factor that has led to escalating coal plant construction costs are the world competition for power plant design and construction resources. It is unreasonable to expect that Wolverine, a relatively inexperienced power plant builder, will be able to avoid cost increases that have affected more experienced power plant builders and operators like Dominion, Duke Power, Alliant Energy, and Consumers Energy.

There are, of course, no guarantees that the construction costs of new coal plants will not increase in future years as a result of the same worldwide competition for power plant design and construction resources, equipment, and commodities that has fueled the recent surge in power plant construction costs. For example, a 15 percent increase in the construction cost of Kansas City Power & Light Company's Iatan 2 coal plant was announced in the spring of 2008, nearly three years into construction. This shows that even plants that are under construction are not immune to cost increases.

In the past utilities were able to secure fixed-price contracts for their power plant construction projects. However, it is not possible to obtain fixed-price contracts for new power plant projects in the present environment. The reasons for this change in circumstances have been explained as follows by a witness for the Appalachian Power Company, a subsidiary of American Electric Power, in testimony before the West Virginia Public Service Commission:

> Company witness Renchek discusses in his testimony the rapid escalation of key commodity prices in the [Engineering, Procurement and Construction] industry. **In such a situation, no contractor is willing to assume this risk for a multi-year project.** Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher.[8] [Emphasis added.]

A fall 2007 assessment of AMP-Ohio's proposed coal-fired power plant similarly noted that the reviewing engineers from Burns and Roe Enterprises:

> agree that the fixed price turnkey EPC contract is a reasonable approach to executing the project. However, the viability of obtaining a contract of this type is not certain. The high cost of the EPC contract, in excess of $2 billion, significantly reduces the number of potential contractors even when teaming of engineers, constructors and equipment suppliers is taken into account. Recent experience on large U.S. coal projects indicates that the major EPC Contractors are not willing to fix price the entire project cost. This is the result of volatile costs for materials (alloy pipe, steel, copper, concrete) as well as a very tight construction labor market. When asked to fix the price, several EPC Contractors have commented that they

8 Testimony of AEP witness William M. Jasper in Case No. 06-0033-E-CN before the Public Service Commission of West Virginia, at page 16, lines 16-20.

> are willing to do so, but the amount of money to be added to cover potential risks of a cost overrun would make the project uneconomical.[9]

It is true that the prices of the commodities used to build power plants have decreased since the middle of last year (2008) and there is some anecdotal evidence that the costs of some short-term construction projects have dropped. However, there has been no evidence that these recent decreases in commodity prices actually have led to lower projected construction costs for long-term construction projects such as new coal plants. In fact, the Engineering News-Record, a respected industry source, has recently reported that both its Building Cost and Construction Cost Indices actually rose between March 2008 and March 2009, as did a power plant-specific construction cost index.[10]

In addition, even though there is now a worldwide economic slowdown, there is still great demand for power plant design and construction resources, equipment and commodities in nations like China and India. At the same time, a number of countries, most particularly the United States and China, have stated their intention to undertake very significant stimulus spending packages on infrastructure repairs and improvements – the Engineering News-Record has reported that these stimulus efforts will pump trillions of dollars into the world economy.[11] Such stimulus spending will increase the demand for the same resources and commodities that are used to build new coal-fired power plants and, therefore, can be expected to again lead to higher commodity prices and power plant construction costs over time.

Unlike its assumed coal plant capital costs, Wolverine's assumed capital costs of $600 per kW for new gas-fired peaking capacity and $1,000 per kW for new gas-fired intermediate capacity (combined cycle) are realistic.[12] For example, in its Fall 2008 modeling of the proposed Nelson E. Dewey 3 CFB coal plant the Staff of the Public Service Commission of Wisconsin used an estimated construction cost for a new combined cycle plant ("CCGT") of $973/kW.[13] This figure is consistent with other estimates of gas plant construction cost, e.g., an article in the October 2007 issue of Power Engineering noted that combined cycle plants could be built for around $750 to $850/kW. Even if an additional 20% is added for owners' costs, these figures suggest an estimated cost $900 per kW to $1,020 per kW.

Xcel Energy has used $806/kW for the capital cost of new CC capacity and $560/kW for the cost of new CT capacity in the modeling for its 2007 Colorado Resource Plan.[14] At

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9 *Consulting Engineer's Report for the American Municipal Power Generating Station located in Meigs County, Ohio,* for the Division of Cleveland Public Power, Burns and Roe Enterprises, Inc., October 16, 2007, at page 11-1.

10 March 23, 2009, at pages 32, 37 and 38.

11 Ibid, at page 18.

12 EGAA, Table 4.6, at page 52 of 114.

13 Rebuttal Testimony of Kenneth J. Detmer in PSCW Docket No. 6680-CE-170, at page 2, lines 11-14.

14 Xcel Energy *2007 Colorado Resource Plan,* Volume 2 Technical Appendix, at page 2-262.

the same time, a report for the Maryland Public Service Commission in November 2007 recommended using capital costs of $670/kW for CT capacity and $950/kW for CC capacity.[15]

The use of realistic capital costs for new natural gas-fired plants and unreasonably low capital costs for new coal plants biases the analysis in favor of coal.

4. Wolverine biased the least cost planning analyses in favor of the baseload coal option by assuming an unreasonably low heat rate.

Wolverine assumed that a new baseload coal plant would achieve a 9100 BTU/kwh heat rate.[16] This is substantially lower than the 9500-9700 range for the heats for new CFB plants in the U.S. reported in the Burns and Roe Enterprises report attached as Appendix A2 to the EGAA.[17] This is also significantly lower than Consumers Energy projects for a new subcritical CFB – 9598 BTU/kwh.[18] The use of the lower heat rate translates into lower fuel costs for the proposed CFB and thus biases the analyses.

Wolverine has not indicated what heat rates it assumed in its cost comparisons between the Rogers City project and lower emitting technologies (i.e., Table 6.4 and Figure 6.6 of the EGAA). If it used the same 9100 BTU/kwh heat rate in these cost comparisons, then they too are biased in favor of the proposed Rogers City project.

5. A comprehensive system for federal regulation of carbon dioxide (CO_2) and other greenhouse gas emissions is inevitable, and it is generally expected that steep emissions reductions will be required. Consequently, all of Wolverine's planning analyses and cost comparisons that do not include a cost for CO_2 emissions should not be considered. This includes most of the least cost planning analyses presented in the EGAA as well as the alternatives cost comparisons presented in Table 6.4 and Figure 6.6.

Corporate, government, and financial leaders anticipate imminent greenhouse gas regulation in the U.S., and that greenhouse gas emission restrictions will pose substantial challenges and create significant new costs for the owners of coal-fired power plants. For example, in its January 28, 2008 assessment of the *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*, Standard & Poor's noted that "the single biggest challenge regulated electric utilities will tackle is the discharge of carbon dioxide (CO_2) into the air."[19]

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15 *Analysis of Options for Maryland's Energy Future*, prepared for the Maryland Public Service Commission by Kaye Scholer LLP, Levitan & Associates, Inc., and SEMCAS Consulting Associates, November 30, 2007, at page 82.

16 EGAA, Table 4.6, at page 52 of 114.

17 Exhibit 17 in Appendix A-2, at page A2-32.

18 Attachment 2 to the response to June 17. 2009 MPSC Question 04, Case No. 15996.

19 *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*, Standard & Poor's, January 28, 2008, at page 2.

Standard & Poor's subsequently issued a report on *The Credit Cost of Going Green for U.S. Utilities* in March 2008, in which it concluded that:

> The debate is over. Not the one concerning climate change, but the one about whether the U.S. will act to limit greenhouse gas emissions to address the possibility that human activities are harming the planet. By now it's a foregone conclusion that the U.S. will pass laws that call for significant reductions in carbon dioxide (CO_2). The only uncertainty is the details of how much and by when….So for electric utilities, the credit question is not so much whether higher costs related to controlling emissions are coming, but rather when and how high they'll actually go.[20]

More recently, in its January 2009 Electric Industry Outlook, Moody's Investors Services also has warned that:

> The prospect for new environmental legislation—particularly concerning carbon dioxide—represents the biggest emerging issue for electric utilities, given the volume of carbon dioxide emissions and the unknown form and substance of potential CO_2 legislation.[21]

Moody's also emphasized that the credit risk for utilities arises from the uncertain costs and format of emissions regulation, acceleration of potential climate change legislation, as well as the possibility that rate regulators will balk at rising costs when consumers reach their tolerance level for cost increases, particularly in light of recessionary pressures.

Regulation of greenhouse gases is inevitable and will increase the cost of running power plants that emit CO_2, particularly those that are coal-fired due to the high carbon content of coal. There are two likely avenues for federal regulation of greenhouse gases. Congress could pass legislation or the U.S. Environmental Protection Agency could adopt regulations to limit greenhouse gas emissions. Both paths are currently under active consideration.

Leaders in both the House and Senate are pursuing plans for aggressive legislative action on climate change during this session. To date, the most substantive legislative proposal is the Waxman-Markey that was recently approved by the House of Representatives. This bill would mandate the following greenhouse gas reduction targets:

- 2020 – 83 percent of 2005 emission levels
- 2050 – 17 percent of 2005 emission levels

Figure Synapse-2, below, shows the emissions trajectories that would be mandated under the proposed Waxman-Markey legislation. These trajectories aim for emissions

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[20] *The Credit Cost of Going Green,* Standard & Poor's, March 2008, at page 15.

[21] *Moody's Global Infrastructure – Industry Outlook: "U.S. Investor-Owned Electric Utilities;"* Moody's Investors Services. January 2009.

reductions of 83 percent from 2005 levels by 2050, similar to the plan recently announced by the Obama Administration.

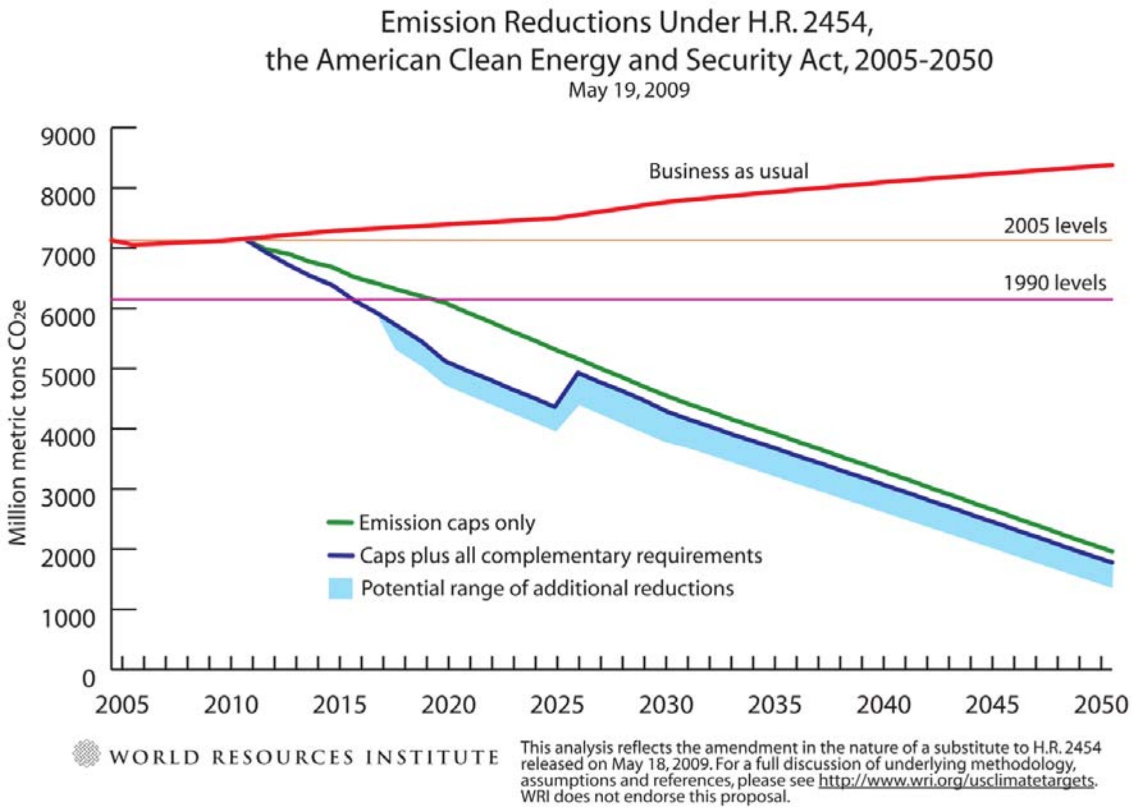

Figure Synapse-2: Emissions reductions that would be required under the Waxman-Markey climate change legislation introduced in the current 111th U.S. Congress.

While Congress debates climate change legislation, the EPA is poised to take the next step towards regulating greenhouse gases under the Clean Air Act. In 2007, the U.S. Supreme Court determined that carbon dioxide is an "air pollutant" under the Clean Air Act, and that EPA has the authority to regulate it.[22] The EPA has now circulated its draft finding, for public comment, that greenhouse gas emissions endanger public health and welfare.[23] The Obama Administration has stated its preference for a legislative solution to addressing climate change; however, EPA's regulatory authority provides an alternate option should Congress fail to act.

The Obama Administration indicated in its recently released Federal budget that it would seek to establish a cap-and-trade system to reduce greenhouse gas emissions to 14 percent below 2005 levels by 2020 and to 83 percent below 2005 levels by 2050. This

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22 In this case, Massachusetts and 11 other states sued the US EPA for failing to regulate greenhouse gas emissions from the transportation sector. The Court found that EPA has the authority and the obligation to regulation greenhouse gas emissions. The court found that EPA's refusal to do so or to provide a reasonable explanation of why it could not regulate was arbitrary, capricious and otherwise not in accordance with law. The Supreme Court also found that the "harms associated with climate change are serious and well recognized."

23 "White House begins review of EPA endangerment proposal," Greenwire, March 23, 2009.

plan would require emissions reductions that approximate the steepest reductions shown in Figure Synapse-2. The Edison Electric Institute (EEI) recently issued "Global Climate Change Points of Agreement" that included an agreement that long-term targets (i.e. 2050) should be an 80 percent reduction below current levels.[24] Given the plans that have been announced in recent months and the proposals that were introduced in the previous Congress, the general trend towards strong federal action to address climate change is clear; and it would be a mistake to ignore it in long-term decisions concerning electric resources. Over time the proposals are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows.

The inevitable adoption of a federal climate change program has several important consequences for Wolverine's EGAA:

(1) Any least cost planning analyses or cost comparisons that do not include any CO_2 costs should not be considered. In particular, the very low levelized busbar costs for the proposed Rogers City CFB coal plant and the other coal and natural gas alternatives presented in Table 6.4 and Figure 6.6 of the EGAA suggest that CO_2 costs are not included in this cost comparison. Consequently, it offers no insights into the relative costs of the proposed Rogers City project and lower emitting alternatives when CO_2 costs are considered. Many of the scenarios examined in the screening curve analyses presented at pages 52 to 61 of the EGAA suffer from the same critical flaw of ignoring CO_2 costs. Those scenarios also should not be considered.

(2) Wolverine claims that adding the Rogers City project would provide the option of reducing CO_2 emissions by as much as 18 percent through the use of sustainable biomass and the improved heat rate efficiency of a new power plant. However, Wolverine does not provide any calculations to support this claim or to show how it's estimated future emissions, shown in Table 6.6, were developed and what assumptions underlay these emissions figures.[25] Moreover, Wolverine only discusses emissions on a lbs/MWh basis, not its total emissions. The inevitable federal greenhouse gas regulation is likely to require reductions in Wolverine's overall emissions. In addition, while an 18 percent reduction in its emissions intensity appears significant, the federal government is considering requiring substantially larger reductions in CO_2 emissions after 2020. Before it is granted an air permit for Rogers City, a plant that may emit more than 4.5 million tons of CO_2 each year for an expected 60 year operating life, Wolverine should be required to produce a plan demonstrating how it will meet the overall emissions levels that will be consistent with the national caps being considered by the federal government.

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24 Edison Electric Institute, "EEI Global Climate Change Points of Agreement," January 14, 2009

25 For example, Wolverine would not answer whether the CO_2 emissions presented in the EGAA include the CO_2 equivalent emissions from nitrous oxide. CFB plants are significant emitters of nitrous oxide, a very potent greenhouse gas.

6. If it operates at an average annual 85 percent capacity factor, the Rogers City CFB plant will emit more than 4.5 million tons of CO_2 each year. Wolverine has not properly considered the costs of these emissions in its costs analyses.

Wolverine has said that it used a $42.14/ton CO_2 price in its least cost planning analyses.[26] However, this cost appears to be in nominal dollars rather than to be a levelized cost over a period of years. Moreover, as indicated above, the very low levelized prices for the coal and gas alternatives presented in Table 6.4 and Figure 6.6 of the EGAA suggest that Wolverine did not assume any CO_2 costs in these analyses. That is a fatal flaw.

Regardless of whether federal restrictions on greenhouse gas emissions ultimately take the form of an emissions cap with tradable allowances, or a tax on emissions, power plant owners (and other emission sources) will bear costs associated with emissions. Since coal is the most carbon-intensive fuel, the compliance costs for a coal-fired power plant are likely to be substantial and must be taken account in such a long-lived investment. For this reason, any and all fossil-fired plant cost analyses in the EGAA that do not include CO_2 costs should not be considered.

In an interview with the Financial Times, Todd Stern, the U.S. Special Envoy on Climate Change, has warned that businesses must not sink money into high-carbon infrastructure unless they are willing to lose their investments within a few years.[27]

> In the Obama administration's starkest rebuke yet to industry over global warming, Todd Stern, special envoy for climate change at the state department, said "high-carbon goods and services will become untenable" as the world negotiated a new agreement to cut carbon emissions. Investors should take note, he warned, that high emissions must be curbed, which would hurt businesses that failed to embark now on a low-carbon path.
>
> "How good will the business judgment of companies that make high-carbon choices now look in five, 10, 20 years, when it becomes clear that heavily polluting infrastructure has become deadly and must be phased out before the end of its useful life?"
>
> Companies investing in such goods and services - such as coal-fired power plants and gas-guzzling cars - could start to incur heavy economic penalties in the near future for their greenhouse gas output.[28]

Moreover, it is not prudent to assume that new coal plants will be grandfathered under any federal regulatory scheme. For example, the 2007 Massachusetts Institute of Technology interdisciplinary study on *The Future of Coal* has warned:

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26 EGAA, at page 59 of 114.

27 http://www.ft.com/cms/s/0/ffb6b5bc-23d3-11de-996a-00144feabdc0.html?nclick_check=1

28 Ibid.

> There is the possibility of a perverse incentive for increased early investment in coal-fired power plants without capture, whether SCPC or IGCC, in the expectation that the emissions from these plants would potentially be "grandfathered" by the grant of free CO_2 allowances as part of future carbon emissions regulations and that (in unregulated markets) they would also benefit from the increase in electricity prices that will accompany a carbon control regime. Congress should act to close this "grandfathering" loophole before it becomes a problem.[29]

Consequently, as Standard and Poor's has explained, it is reasonable to expect that:

> Customers of those utilities with higher levels of carbon intensity will be more exposed to rate increases than customers of utilities with lower carbon intensity. The magnitude of the rate increases will depend on the level of carbon costs and the extent of management's commitment to the preservation of credit quality.[30]

Numerous modeling analyses of federal policy proposals for mandatory greenhouse gas reductions in the U.S are available (e.g. Energy Information Administration and the Environmental Protection Agency, educational institutions such as the Massachusetts Institute of Technology and Duke University, consulting firms, and various other organizations). A list of these analyses is given in Attachment No.1 to these Comments. Though these analyses precede the recent legislative proposals from the Administration and Congress, their results are relevant because the greenhouse gas emission reduction targets in recent proposals are comparable to the most stringent targets in the plans that have been modeled.

In total, these modeling analyses examined more than 75 different scenarios. These scenarios reflected a wide range of assumptions concerning important inputs such as: the "business-as-usual" emissions forecasts; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress and the cost of alternatives; and the presence or absence of a "safety valve" price.

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29 *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, 2007, at page (xiv). Available at http://web.mit.edu/coal/The_Future_of_Coal.pdf.

30 Standard and Poor's, *The Cost of Carbon – Credit Quality Implications for Public Power and Cooperative Utilities*, March 27, 2008, at page 9.

Based on a number of factors, including our assessment of the results of these modeling analyses, Synapse has developed a set of CO_2 price forecasts that we believe provides a reasonable range of possible future CO_2 allowance values. The current Synapse CO_2 price forecasts are compared to Wolverine's $42.14/ton figure (in nominal dollars) in Figure Synapse-3 below:

Figure Synapse-3: Synapse 2008 vs. Wolverine CO_2 allowance price forecasts. [31]

The 2008 Synapse CO_2 Price Forecasts shown in Figure Synapse-3 are all in 2007 dollars. The Synapse Low CO_2 Price Forecast starts at $10/ton in 2013 and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030. The 2008 Synapse High CO_2 Price Forecast starts at $30/ton in 2013 and rises to approximately $68/ton in 2030. This High Forecast represents a $45/ton levelized price over the period 2013-2030. Synapse also has prepared a Mid CO_2 Price Forecast that starts close to the low case, at $15/ton in 2013 and climbs to $53/ton by 2030. The levelized cost of this Mid CO_2 price forecast is $30/ton.

Synapse first developed a set of CO_2 price forecasts in the spring of 2006. However, significant developments since that time led Synapse to re-examine and raise those CO_2 price forecasts in the summer of 2008 to ensure that they reflect an appropriate level of financial risk associated with greenhouse gas emissions.[32] Most importantly, the political support for serious climate change legislation has expanded significantly in federal and

[31] This figure assumes that Wolverine's $42.14/ton CO_2 price was in 2015 nominal dollars.

[32] See the July 2008 report *Synapse 2008 CO2 Price Forecasts* available at http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf

state governments, as well as in the public at large, as the scientific evidence of climate change has become more certain. Concurrently, the greenhouse gas regulation bills under consideration in the 110th U.S. Congress contained emissions reductions that were significantly more stringent than would have been required by proposals introduced in earlier years. Moreover, an increasing number of states have adopted policies, either individually and/or as members of regional coalitions, to reduce greenhouse gas emissions. Further, additional information has been developed regarding technology innovations in the areas of renewable resources, energy efficiency, and carbon capture and sequestration, leading to greater clarity about the cost of emissions mitigation; however, cost estimates for many of these technologies are still in the early stages. Taken together these developments lead to higher financial risks associated with future greenhouse gas emissions and justify the use of higher projected CO_2 emissions allowance prices in electricity resource planning and selection for the period 2013 to 2030.

Figure Synapse-4, below, compares the levelized CO_2 cost used by Wolverine and the range of CO_2 prices that Synapse recommends be used for resource planning with the results of the modeling analyses of the major climate change bills that have been proposed in the U.S. Congress. As can be seen, the CO_2 prices recommended by Synapse are very reasonable compared to the range of CO_2 emissions allowance prices that could have resulted from adoption of the major greenhouse gas regulatory legislation that has been considered in the U.S. Congress. In fact, under many possible scenarios, CO_2 allowance prices could substantially exceed the high ends of the price range that Synapse recommends for use in resource planning assessments.

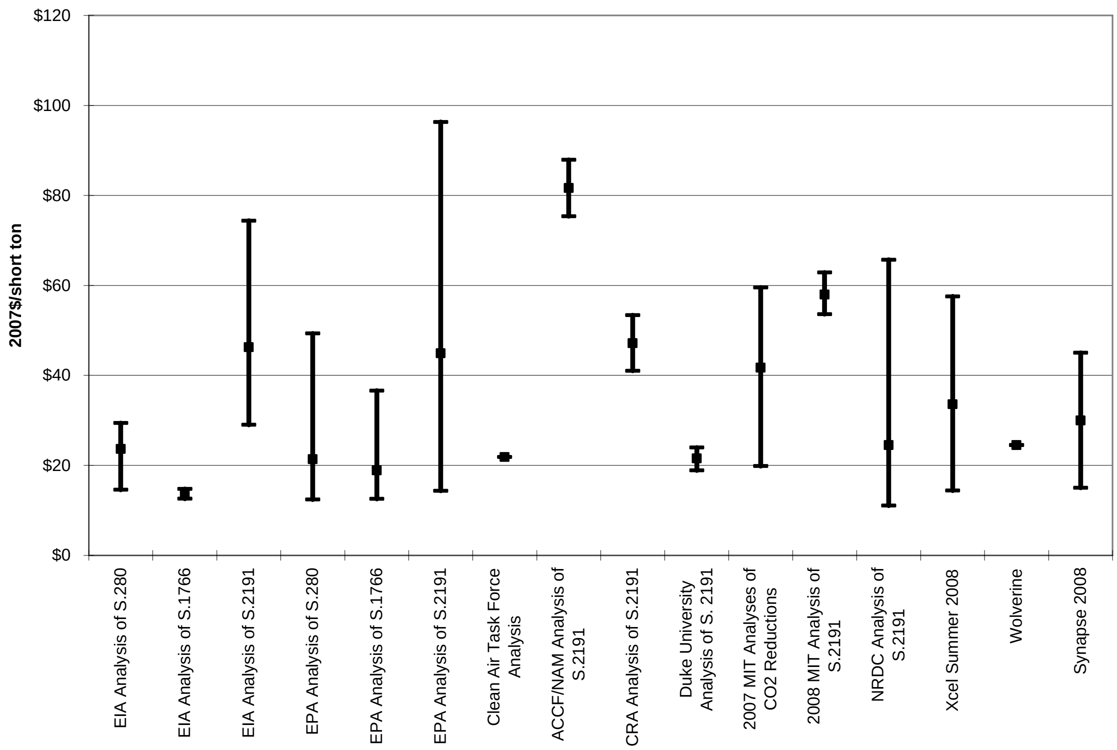

Figure Synapse-4: **CO_2 prices used by Synapse and Wolverine vs. results of modeling analyses of major bills in the U.S. Congress – levelized CO_2 prices (2013-2030, in 2007 dollars).** [33]

In fact, there are a significant number of possible scenarios where CO_2 emissions allowance prices could be substantially higher than the CO_2 price that Wolverine used in the EGAA.

7. The inevitable regulation of greenhouse gas emissions by the federal government will require the State of Michigan to reduce its current heavy dependence on coal-fired power plants.

Wolverine claims that the state of Michigan will need new coal-fired power plants like the Rogers City project to replace its aging coal fleet.[34] We agree that over time the state's existing coal-fired power plants will have to be retired, in large part to reduce greenhouse gas emissions to levels consistent with the national caps in legislation like the Waxman-Markey bill. However, this existing coal fleet will have to be replaced with lower emitting technologies such as wind, energy efficiency and natural gas, not the construction of new coal-fired power plants. For example, Table 6.7 in the EGAA shows that a wind & gas turbine portfolio would emit only about 30 percent of the CO_2 as a new

[33] This figure assumes that Wolverine's \$42.14/ton CO_2 price was in 2015 nominal dollars.

[34] EGAA, at pages 64 to 66 of 114.

CFB plant burning pet coke, coal and biomass.[35] Adding more energy efficiency would reduce the CO_2 emissions of the alternative portfolio even further.

Figure Synapse-5, below, shows Michigan's recent statewide CO_2 emissions and the emission levels that would be consistent with the national caps in the Waxman-Markey legislation. As can be seen, substantial overall reductions in the state's CO_2 emissions will be required during the coming decades.

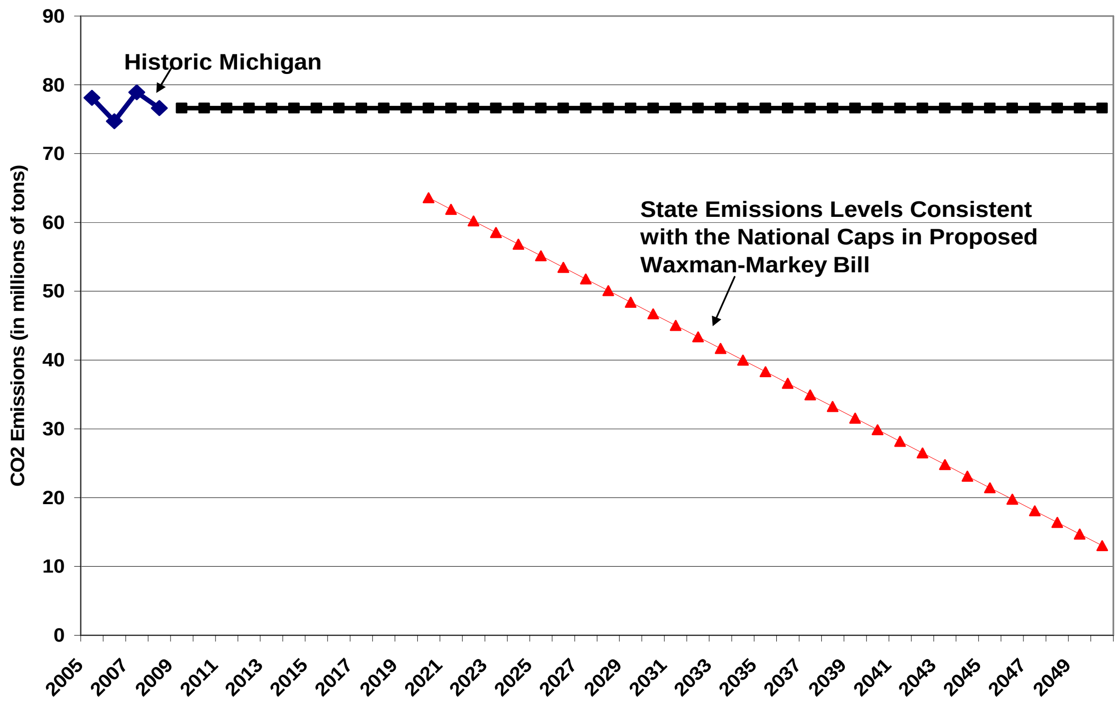

Figure Synapse-5: **The State of Michigan's Historic and Future CO_2 Emissions compared to the Emission Levels that Would Be Consistent with the National CO_2 Caps in the proposed Waxman-Markey Legislation.**

If Michigan replaces old coal units with new coal plants, it will have to purchase substantial amounts of expensive allowances or offsets to meet the declining federal caps. On the other hand, if the state gradually replaces old coal with cost-effective energy efficiency, renewables, and, to the minimum amount necessary, gas, it would put itself into a position of possibly being able to sell allowances into the national market to the benefit of ratepayers and the economy.

8. Wolverine's assumption of a very high natural gas price in its Carbon Tax Scenario biases its cost analyses in favor of the coal alternative.

Wolverine looks at a range of possible natural gas prices in its EGAA. However, when it considers the possible regulation of greenhouse gas emissions in a "Carbon Tax Scenario" Wolverine only assumes a single natural gas price – its mid price forecast. It does not look at lower or higher gas price scenarios with a carbon tax or federal cap-and-

35 EGAA, at page 103 of 114.

trade program. As we will discuss in another comment below, a comprehensive system for federal regulation of CO_2 and other greenhouse gas emissions is inevitable. For this reason, the scenarios that Wolverine examined without any CO_2 prices lack any probative value and should be given no weight.

Wolverine has said that the $7.99/MMBtu base case gas price shown in Figure 4.6 in its EGAA "is from Table 13 of the Energy Information Administration (EIA) Annual Energy Outlook released March 2009."[36] A review of this Table, however, suggests two significant flaws. First, the $7.99/MMBtu cost used by Wolverine appears to be for the year 2015 rather than representing a levelized cost for a longer planning period. Second, Table 13 in the AEO represents an average natural gas price for the entire nation, that includes higher priced locations on the east and west coasts.

It would have been more appropriate for Wolverine to have used the information on the gas prices for electric generation in the East Central Area Reliability Coordination Agreement (ECAR) region that were presented in Table 72 of the AEO. This region includes Michigan.

The gas price projections included in Table 72 of the AEO for the ECAR region are significantly lower than the national gas prices included in Table 13, as can be seen from Figure Synapse-6 below.

[36] Answer 14 in Wolverine's June 23, 2009 responses to Staff questions generated during a June 15, 2009 meeting, at page 16.

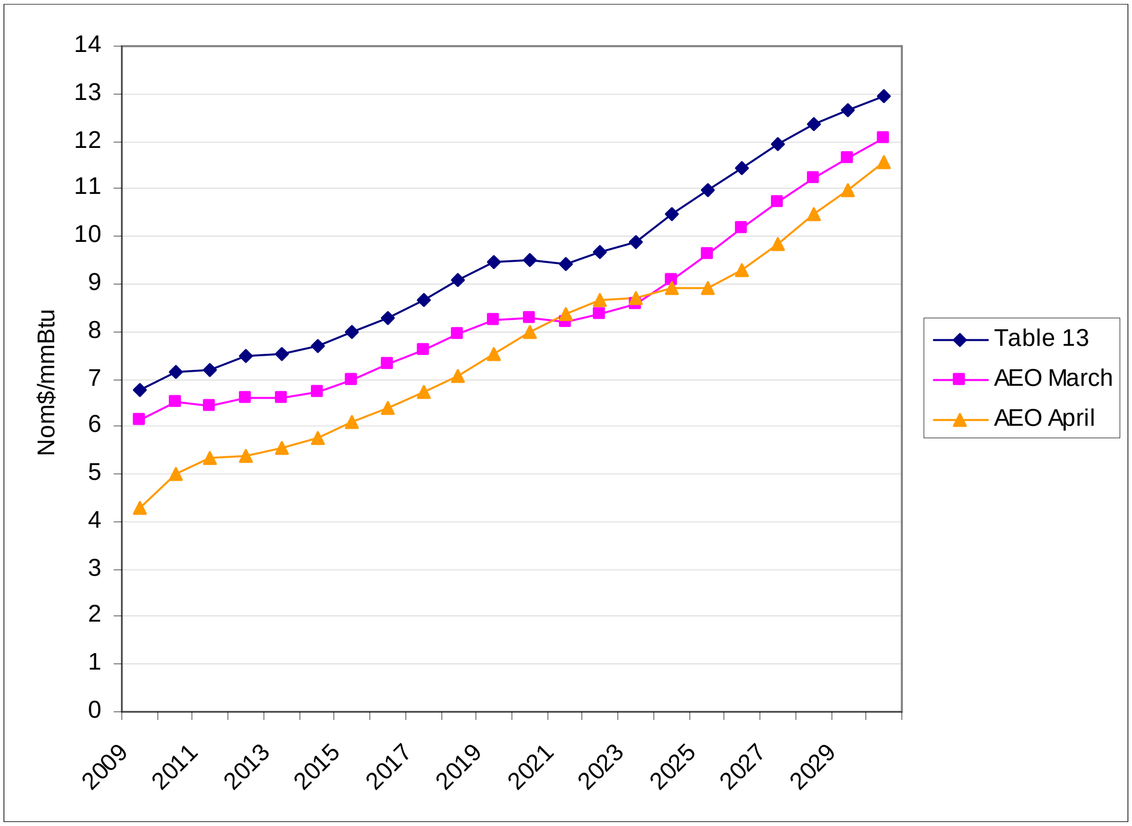

Figure Synapse-6: **Natural Gas Prices – Table 13 of March AEO Used by Wolverine vs. ECAR Region Gas Prices Forecast in Table 72 of the March 2009 AEO and Table 72 of April 2009 AEO.**

As noted above, in the absence of workpapers, it appears that the $7.99/MMBtu natural gas that Wolverine assumed in its cost analyses in the EGAA was taken from the value for the year 2015 in Table 13 of the March 2009 AEO. The comparable natural gas price in the March 2009 AEO for 2015 for the ECAR region was only $6.07/MMBtu, or approximately 24 percent lower than the figure used by Wolverine. The comparable natural gas price in the April 2009 AEO for 2015 for the ECAR region was only $5.31/MMBtu, or nearly 34 percent lower than the figure used by Wolverine.

Wolverine cites a number of factors that it believes make higher natural gas prices more likely.[37] However, Wolverine's analysis contradicts that of other utilities and forecasts which have noted a structural change in the natural gas markets over the last year. For example, Entergy Louisiana, in announcing that it was suspending construction of a new coal-fired power plant, explained in some detail the structural changes in the natural gas market that had led to the expectation that future gas prices would be much lower than previously anticipated:

[37] EGAA, at page 58 of 114.

4. Recent Natural Gas Developments

> Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.
>
> *   *   *   *
>
> However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run….
>
> *   *   *   *
>
> Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods…[38]

Entergy's conclusion that there has been a recent seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the Potential Gas Committee, the authority on gas supplies. This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[39] The existence of higher reserves and the new recovery techniques discussed by Entergy support the conclusion that future natural gas prices should not be nearly as high as was forecast last year or even earlier this year.

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[38] Id, at pages 17, 18 and 22.

[39] *Estimate Places Natural Gas Reserves 35 percent Higher,* New York Times, June 9, 2009.

9. There is no evidence to support Wolverine's claim that carbon regulation would increase the price of natural gas by 25 percent or more.

It is possible that natural gas demand could be higher due to CO_2 emission regulations and, as a result, natural gas prices could be expected to be somewhat higher than otherwise would be the case. However, the effect is very complicated and will depend on a number of factors such as: how much new natural gas capacity is built as a result of the higher coal-plant operating costs due to the CO_2 emission allowance prices; how much additional energy efficiency and renewable alternatives are added to the U.S. system; the levels and prices of any incremental natural gas imports or sources developed in the U.S.; and changes in electric system dispatch. Indeed, depending on future circumstances there may be some periods in which the prices of natural gas may be lower as a result of CO_2 regulations. Thus it is very difficult to determine, at this time, the amount by which natural gas prices might change due to CO_2 emission regulations.

As part of our work on climate change issues, Synapse has reviewed the results of the modeling analyses that evaluate the CO_2 emissions allowance prices and other impacts of greenhouse gas regulatory legislation. For this work we have looked at the publicly available data on the impact that CO_2 regulatory legislation could have on natural gas prices.

Instead of relying on the results of the publicly available modeling analyses that have studied the impact of greenhouse gas regulation on natural gas prices or assuming a range of possible natural gas changes that reflect this uncertainty, Wolverine has merely assumed in its carbon tax scenarios that the adoption of even relatively low CO_2 prices would lead to a substantial (i.e., 25 percent or higher) increase in natural gas prices. This assumption of a significant increase in the price of natural gas in those scenarios with CO_2 prices biased the analyses against any alternatives that include natural gas-fired generation and in favor of the coal alternatives.

Figure Synapse-7, below, shows the levelized percentage changes in natural gas prices (i.e., increases or decreases from the base case with no regulation of greenhouse gas emissions) in scenarios reflecting the major climate change proposals in the U.S. and the levelized CO_2 prices in those scenarios. The data presented in Figure Synapse-7 has been developed from the results of modeling by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change, the U.S. EPA, and the Energy Information Administration ("EIA") of the Department of Energy , and cover multiple climate change proposals in the 110th U.S. Congress: Senate Bill S.280 (the McCain-Lieberman bill), Senate Bill S.1766 (the Bingaman-Specter bill) and Senate Bill S.2191 (the Lieberman-Warner bill).

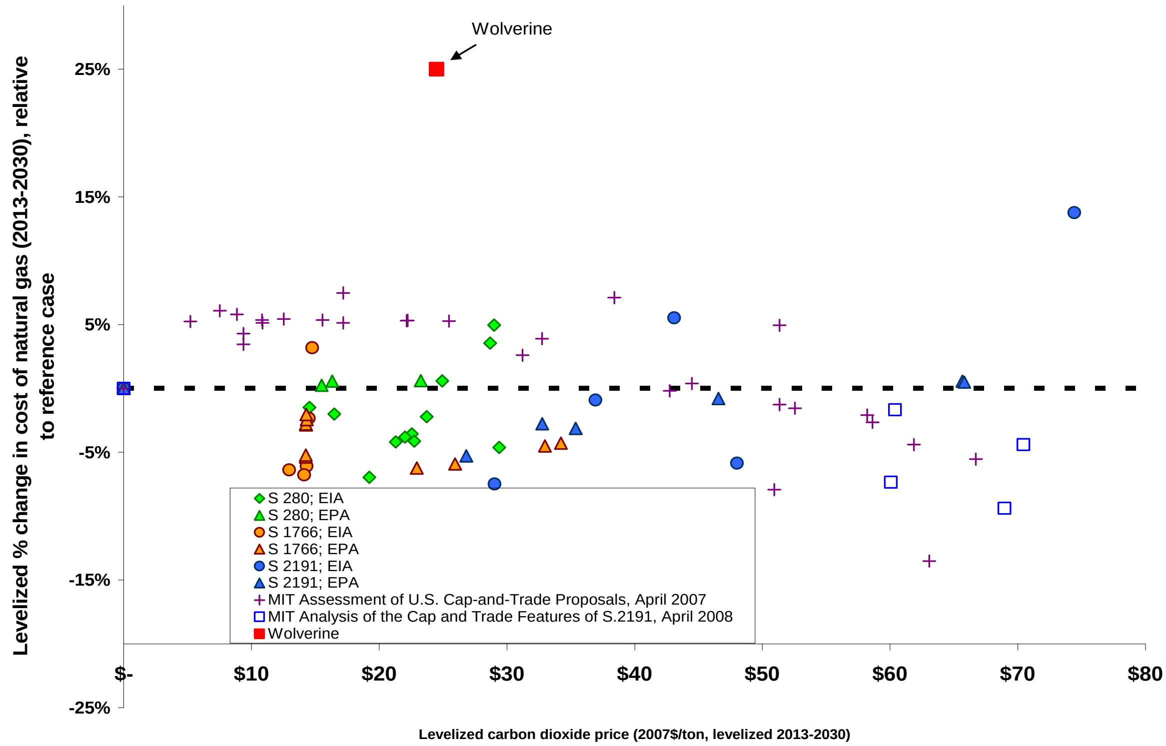

Figure Synapse-7: **The relationship between CO_2 emissions allowance prices and natural gas prices.**

As shown clearly in Figure Synapse-7, Wolverine has assumed that there would be a very significant increase (that is, 25 percent) in the price of natural gas at a relatively low levelized CO_2 price. This assumption is not supported by the results of the independent modeling analyses of carbon dioxide regulation. Instead, as can be seen from Figure Synapse-7, in all but one of the scenarios studied, federal regulation of greenhouse gas emissions would have a much smaller impact on natural gas prices than Wolverine has assumed – and that single scenario featured a levelized CO_2 price of approximately $75/ton, a far higher price than Wolverine has assumed for the least cost planning studies included in the EGAA. In fact, in some of the carbon regulation scenarios represented in Figure Synapse-7, the models forecast that the adoption of greenhouse gas regulation might lead to lower natural gas prices as demand for and use of natural gas declined due to its greenhouse gas emissions. Thus, there is no evidence to support Wolverine's assumption that federal regulation of greenhouse gas emissions would inevitably lead to a 25 percent or higher increase in the price of natural gas, particularly at relatively low CO_2 prices.

A recent study by the U.S. Department of Energy's National Renewable Energy Laboratory examining the costs and benefits of achieving 20 percent wind energy penetration by 2030 provides additional evidence in support of a conclusion that carbon regulation will not significantly increase natural gas prices.[40] It is generally accepted that

40 *20 Percent Wind Energy by 2030*, available at http://www.20percentwind.org/20p.aspx?page=Report.

strategies for reducing our national greenhouse gas emissions will require implementing complementary policies adding large amounts of new wind and energy efficiency. One of the benefits that the recent DOE study found was that wind generation could displace up to 50 percent of the electricity that would be generated from natural gas – this, in turn, could translate into a reduction in national demand for natural gas of 11 percent.[41] Thus, carbon legislation, when coupled with increasing amounts of new wind and energy efficiency, may lead to decreases in the demand for and the costs of natural gas over the long term, counter to what Wolverine has claimed.

10. Wolverine's analyses are biased against new wind facilities by the failure to include a wind capacity credit.

Contrary to the developing industry view, Wolverine does not attribute any capacity credit to wind facilities. Thus, it requires that there be 100 percent backup from gas turbine capacity in the wind & gas scenario presented in Table 6.4 and Figure 6.6. This increases the cost of wind & gas scenario because it overbuilds otherwise unnecessary gas turbine capacity. Even Consumers Energy assumes a low 12.5 percent capacity credit for wind in its EGAA.

11. Wolverine unreasonably assumes that its members will not be able to achieve more than 0.2 percent annual incremental energy efficiency savings after the year 2015.

Wolverine increases its future need for new capacity by reducing its projected incremental annual energy efficiency savings from 1 percent in 2015 to 0.2 percent between 2016 and 2021, the last year of its analysis.[42] This is based on Wolverine's assertion that a cumulative 8.2 percent of energy efficiency savings by 2030 is a reasonable level to assume for planning purposes.[43] However, Wolverine's assumed savings are overly conservative for a number of reasons:

(1) Wolverine provides no company- or even state-specific evidence to support its claim that it cannot achieve more that this amount of cost-effective energy efficiency each year after 2015. Unlike many other utilities, including investor-owned, public, and electric membership cooperatives, Wolverine and its members appear to have not prepared member-specific energy efficiency potential studies for their own service territory. Therefore, it has no evidentiary basis for concluding that higher energy efficiency savings cannot be achieved after 2015.

(2) The available evidence suggests that the cost of achieving energy efficiency in Michigan is significantly less than the estimated levelized costs of the proposed Rogers City project. For example, Consumers Energy's EGAA notes that energy efficiency has a levelized cost, on average, of only $35 per MWh.[44] This average

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41 Id, at pages 16 and 154.

42 EGAA, at page 25 of 114.

43 Id.

44 EGAA, Table 7, at pages 36 and 37.

cost is substantially less than the levelized costs of the coal and natural gas supply side options presented in Table 6.4 of Wolverine's EGAA. Given a very low average cost such as this, it is reasonable to expect that there would be a substantial amount of untapped energy efficiency potential in Consumers Energy's service territory that would cost less than even the $69/MWh to $84/MWh that Wolverine claims the cost of power from the proposed Rogers City CFB plant.[45] Wolverine should be required to include these lower cost energy efficiency savings before it is allowed to build the more expensive Rogers City project.

(3) The 0.2 percent annual energy efficiency savings that Wolverine projects for the years 2016 to 2021 is substantially below the 2 percent annual savings that the Midwest Governors Association has set as its target.[46]

(4) As discussed in Attachment No. 2 to these Comments, the federal government has taken aggressive actions in recent years to fund energy efficiency programs and to stimulate the development and use of renewable resources. It is unclear from the EGAA whether Wolverine assumed energy efficiency savings reflect these aggressive actions.

(5) As discussed in Attachment No. 3 to these Comments on Wolverine Power Cooperative's EGAA, the EPRI study on which Wolverine seeks to rely is flawed and, consequently, understates the potential for energy efficiency savings.

(6) If Consumers had been sufficiently motivated to perform an analysis of the available cost effective potential for energy efficiency in its service territory, there is ample evidence to suggest that it would have found the potential to save considerably more than 0.5 percent per year in 2016 and beyond. In fact, some Midwest states' utilities are already achieving greater energy savings than 0.5 percent per year, including Iowa and Minnesota whose utilities saved 0.7 percent and 0.6 percent of load in 2006, respectively, and many states outside the Midwest are achieving much higher savings including Vermont and Connecticut, whose utilities cut demand by 1.8 percent and 1.3 percent in 2007 using energy efficiency. Recent energy efficiency potential studies have projected achievable cost-effective energy efficiency potential at levels more than double that projected by Consumers, including Kansas (1.1% achievable[47]), Florida (1.3% achievable[48]), Texas (1.2% achievable[49]), and Vermont (1.9% achievable[50]).

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45 As noted above, these very low levelized busbar costs for power from a new CFB strongly suggest that they do not include CO_2 costs.

46 *Energy Security and Climate Stewardship Platform for the Midwest*, Midwestern Governor's Association, November 2007, at page 7. Available at http://www.midwesternaccord.org/Platform.pdf.

47 Energy Efficiency Potential Study for the State of Kansas, Prepared by Summit Blue Consulting, August 11, 2008.

48 Elliott et al,, Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demand, June 2007, ACEEE Report No. EO72.

In conclusion, Wolverine's assumption that it will be able to achieve only 0.2 percent incremental annual energy efficiency savings starting in 2016 is unsupported and should not be accepted. Instead, Wolverine should be required to undertake and present the results of a company-specific assessment of the potential for cost-effective energy efficiency and to update the EGAA to reflect these results accordingly before it is granted a permit for the Rogers City project.

12. The EGAA ignores the availability of a substantial amount of under-utilized gas-fired combined cycle and gas turbine capacity that could provide much, if not all, of the energy that would be generated at the proposed Rogers City CFB coal plant.

There is a substantial amount of under-utilized natural gas-fired generating capacity both in Michigan and neighboring states. In its recently filed EGAA, Consumers Energy acknowledges the existence of this under-utilized gas-fired capacity when it assumes that a new combined cycle plant would operate at a capacity factor of only 15 percent and that a new combustion turbine would operate at a capacity factor of only 3 percent.[51] Consumers Energy says that these low capacity factors are based on historical operating experience and its modeling.

A review of the generation data in the U.S. EPA's Clean Air Markets Database confirms that there is significant under-utilized natural gas-fired capacity in Michigan and the neighboring states of Ohio and Indiana. Given the very slow load and energy sales growth projected for this region, it is reasonable to expect that these gas-fired plants will continue to be under-utilized for years to come.

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49 Elliott et al, Potential for Energy Efficiency and Renewable Energy to Meet Texas's Growing Energy Demand, March 2007, ACEEE Report No. EO 73.

50 Vermont Electric Energy Efficiency Potential Study, Prepared for the Vermont Department of Public Service by GDS Associates, Inc., January 2007.

51 Consumers Energy Balanced Energy Initiative Electric Generation Alternatives Analysis, dated June 2009, Footnotes Numbers 48 and 49, on page 36.

State	Plant	Nameplate Capacity	2008 Capacity Factor
MI	Ada Cogeneration LP	33	71.2%
MI	Covert Generating Project	1,176	7.9%
MI	Dearborn Industrial Generation	760	17.2%
MI	Kinder Morgan Power Jackson Facility	570	9.2%
MI	Michigan Power LP	154	66.2%
MI	Midland Cogeneration Venture	1,849	33.8%
MI	University of Michigan	45	40.6%
MI	Zeeland Plant	591	9.4%
OH	Ashtabula	26	63.7%
OH	AEP Waterford Facility	922	3.3%
OH	Hanging Rock Energy Facility	1,322	6.7%
OH	Washington Energy Facility	600	6.1%
IN	Lawrenceburg Generating Station	1,232	4.6%
IN	Noblesville	328	14.2%
IN	Portside Energy	76	35.7%
IN	Sugar Creek Power Plant	555	5.2%
IN	Whiting Clean Energy	639	15.2%

Table Synapse-2: Natural Gas-Fired Generating Units in Michigan, Ohio and Indiana – 2008 Capacity Factors.

Before its Alternatives Analysis is accepted, Wolverine should be required to demonstrate that producing additional energy at its existing gas-fired facilities is not a cost-effective alternative to the proposed Rogers City project. Wolverine also should be required to demonstrate that purchasing capacity and energy from existing gas-fired facilities owned by other companies is not a more cost-effective option than building a new, and expensive, coal-fired power plant.

13. Uncertainty over construction costs and the costs of complying with future federal carbon dioxide emission reduction requirements have, in significant part, led to more than 90 coal power plant cancellations, delays and rejections by state regulatory commissions.

Consumers Energy is one of many utilities that have considered investing in new coal-fired power in recent years. Public and investor-owned utilities and state regulatory commissions and officials have recognized the risks associated with new coal plant investments under current circumstances and have chosen to cancel, delay or reject more than 90 proposed coal-fired power plants.

In fact, more than thirty proposed coal-fired plants have been cancelled in just the three years since early 2006. More than forty others have been delayed. Although some proposed plants have been approved, state regulatory Commissions in North Carolina, Florida, Virginia, Oklahoma, Washington State, Oregon, and Wisconsin have rejected proposed power plants.

Regulators have cited several reasons for cancelling new coal construction. For example, the July 2007 decision of the Florida Public Service Commission denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties of plant construction costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.[52]

In April of 2008, the Virginia State Corporation Commission rejected a proposed coal plant citing uncertainties of costs, technology, and unknown federal mandates.[53] The Commission concluded that "… [Appalachian Power Company] has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in [Appalachian Power Company's] service territory to assume."[54]

The Commission also noted the uncertainties surrounding federal regulation of carbon emissions, and carbon capture and sequestration technology and costs, and observed that the Company was asking for a "blank check."[55] On this basis, the Commission concluded that "We cannot ask Virginia ratepayers to bear the enormous costs – and potentially huge costs – of these uncertainties in the context of the specific Application before us."[56]

Then, in November 2008, the Public Service Commission of Wisconsin rejected the proposed 300 MW (net) Nelson E. Dewey CFB coal-fired power plant. The Commission decided that the $1.26 billion project was too costly when weighing it against other alternatives such as natural gas generation and the possibility of purchasing power from existing sources.[57] The Commission also said that "Concerns over construction costs and uncertainty over the costs of complying with future possible carbon dioxide regulations were all contributing factors to the denial."[58]

At the same time, a large number of investor-owned and public power utilities have cancelled or delayed new coal-fired generating facilities. For example:

- Tenaska Energy cancelled plans to build a coal-fired power plant in Oklahoma in July 2007 because of rising steel and construction prices. The Company's general manager of business development explained that:

  > ... coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.

[52] Florida Public Service Commission, Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.

[53] Final Order in Case No. PUE-2007-00068, April 14, 2008. Available at http://scc.virginia.gov/newsrel/e_apfrate_08.aspx.

[54] Id, at page 5.

[55] Id, at page 10.

[56] Id, at page 10.

[57] The estimated cost of the proposed coal plant was $1.26 billion for a 326 MW facility.

[58] *PSC Rejects Wisconsin Power & Light's Proposed Coal Plant*, issued by the Public Service Commission of Wisconsin on November 11, 2008.

> And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot… At one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.
>
> We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it.[59]

- The publicly-owned Great River Energy Generation & Transmission Cooperative ("GRE") in Minnesota announced in September 2007 its withdrawal from the proposed Big Stone II Project. According to GRE, four factors contributed most prominently to the decision to withdraw, including uncertainty about changes in environmental requirements and new technology and the fact that "The cost of Big Stone II has increased due to inflation and project delays."[60]

- Similarly, in the spring of 2008, Associated Electric Cooperative, Inc., the wholesale power supplier for 57 electric cooperatives in Missouri, southeast Iowa, and northeast Oklahoma, delayed its plans to build the Norborne 660 MW coal-fired power plant due to increasing costs and other uncertainties. According to AECI:

> The Norborne project costs have significantly increased in less than three years and are now estimated at $2 billion due to worldwide demand for engineering, skilled labor, equipment and materials.
>
> The U.S. Department of Agriculture Rural Utilities Service, a traditional funding source for rural electric cooperatives, is currently unable to finance baseload generation for cooperatives. Although AECI's AA credit rating is one of the strongest ratings among all electric utilities nationally, seeking private lending would further increase project costs.[61]
>
> There also is increasing uncertainty in the regulatory environment, and Congress continues to debate the environmental and economic

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[59] Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

[60] See www.greatriverenergy.com/press/news/091707_big_stone_ii.html.

[61] The Rural Utilities Service of the U.S. Department of Agriculture announced in early March 2008 that it was suspending the program through which it makes loans to rural cooperatives to build new coal-fired power plants. In a letter to Congress, the Administrator of Utility Programs for the Department of Agriculture indicated that loans for new base load generation plants would not be made until the RUS and the federal Office of Management and Budget can develop a subsidy rate to reflect the risks associated with the construction of such plants.

> impact of reducing greenhouse gas emissions, making the cost of reducing carbon dioxide from power plants unknown.[62]

At the same time, AECI noted that it would continue to look at energy efficiency initiatives, natural gas, renewable and nuclear resources to address future generation needs.

Current circumstances are causing more utilities to reconsider their earlier decisions to build coal plants. For example:

- In February 2009, NV Energy, Inc. announced the postponement, due to increasing environmental and economic uncertainties, of its plans to construct a coal-fired power plant in East Nevada. The company has said that it will not proceed with construction of the coal plant until the technologies that will capture and store greenhouse gasses are commercially feasible, which it believes is not likely before the end of the next decade.[63]
- Then in early March 2009, Alliant Energy cancelled its plan to build a proposed 649 MW coal-fired plant in Marshalltown, Iowa. According to Alliant, the decision to cancel the project was based on a combination of factors including "the current economic and financial climate; increasing environmental, legislative and regulatory uncertainty regarding regulation of future greenhouse gas emissions" and the terms placed on the proposed power plant by regulators.[64]
- On April 9, 2009, the Board of Tri-State Generation & Transmission, which supplies wholesale power to 18 electric distribution cooperatives in Colorado and 26 in Wyoming, New Mexico and Nebraska, voted to shift its focus from building 2 or 3 proposed coal plants to natural gas, renewable energy and efficiency.[65]
- In mid-May 2009, four Electric Membership Corporations withdrew from the proposed Plant Washington coal project in Georgia, citing high costs and concerns about the uncertainties surrounding federal climate legislation.
- In late 2007 the Louisiana Public Service Commission approved Entergy Louisiana's proposal for the Little Gypsy Repowering Project that would convert an existing natural gas-fired plant into one that burns coal. However, in March 2009, the Louisiana Commission ordered the company to suspend on-going project activities and to demonstrate that the project was still viable.[66] The

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62 http://www.aeci.org/NR20080303.aspx.

63 http://www.lasvegassun.com/news/2009/feb/09/nv-energy-postponing-big-coal-fired-plant-near-ely/.

64 http://www.alliantenergy.com/Newsroom/RecentPressReleases/023120.

65 "Tri-State changes course, says it will develop gas, renewables over coal," Denver Business Journal, April 11, 2009. Available at http://www.bizjournals.com/denver/stories/2009/04/06/daily99.html.

66 http://blog.nola.com/tpmoney/2009/03/psc_orders_entergy_louisiana_t.html

estimated cost of the project had increased from an initial $910 million to $1.76 billion.

In response, Entergy Louisiana has requested a three year extension for the suspension of on-going project activities based on its conclusion that "Given current forecasts of natural gas prices, it now appears that the [combined cycle gas turbine] alternative may be more economic than the [coal-fired] Repowering Project across a range of assumptions."[67] Entergy also explained in detail the changed circumstances that had led it to the conclusion that project activities should be suspended:

> Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.
>
> The proposed changes in various energy policies by the Obama administration also could have significant effects on the future economics of the Repowering Project. While this administration has only been in office since mid-January, it is becoming more likely that a Renewable Portfolio Standard ("RPS") soon could be implemented. An RPS will require utilities such as [Entergy Louisiana] to incorporate various new technologies into their long-term resource portfolios, including the potential for baseload resources such as biomass facilities and various other intermittent resources such as wind or solar powered generation. The effects of an RPS could mandate that up to 25 percent of a utility's total energy requirements be provided by renewable resources….
>
> With regard to CO_2 legislation, while the Commission and the Company certainly anticipated that CO_2 regulation would be in place over the life of this Project and incorporated CO_2 compliance costs into its evaluation, there seems to be an emerging momentum to implement CO_2 legislation during the next one to two years. If this occurs, it will allow the Company to gain much greater certainty regarding the cost of compliance with CO_2 legislation and how it will affect the Project economics. CO_2 costs, as the Company has always made clear, are an important factor in the Project economics, and while the possible implementation of CO_2

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[67] *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted y Entergy Louisiana on April 1, 2009, at page 12.

> legislation is not the reason to delay the Project, one of the benefits of the longer-term delay will be greater level of certainty regarding this cost.[68]

These are only a few examples of the many public and investor-owned utilities, as well as utility regulators, which have decided in recent years to cancel or significantly delay proposed coal-fired power plants.

[68] Ibid, at pages 6-8.

Attachment No. 3
List of Analysis of Proposed Federal Greenhouse Gas Legislation

The Energy Information Administration of the U.S. Department of Energy's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007). Available at http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf.

The October 2007 Supplement to the EIA's assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*. Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf

The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008). Available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf

The EIA's assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008). Available at http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.

The U.S. Environmental Protection Agency's ("EPA") *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007). Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

The EPA's *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008). Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

The EPA's *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008). Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

Assessment of U.S. Cap-and-Trade Proposals by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change (April 2007). Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf.

Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191 by the Joint Program at MIT on the Science and Policy of Global Change (April 2008). Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.

The Lieberman-Warner America's Climate Security Act: A Preliminary Assessment of Potential Economic Impacts, prepared by the Nicholas Institute for Environmental Policy Solutions, Duke University and RTI International (October 2007). Available at http://www.nicholas.duke.edu/institute/econsummary.pdf.

U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways, prepared by the International Resources Group for the Natural Resources Defense Council (May 2008). Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf.

The Lieberman-Warner Climate Security Act – S. 2191, Modeling Results from the National Energy Modeling System – Preliminary Results, Clean Air Task Force (January 2008). Available at http://lieberman.senate.gov/documents/catflwcsa.pdf.

Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model, CRA International, April 2008. Available at http://www.nma.org/pdf/040808_crai_presentation.pdf.

Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM), a report by the American Council for Capital Formation and the National Association of Manufacturers, NMA, March 2008. Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.

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Memorandum

To: NRDC and Sierra Club

From: Synapse Energy Economics

Date: June 26, 2009

Re: Sources of Funding relevant to Michigan within the American Recovery and Reinvestment Act (ARRA)

The American Recovery and Reinvestment Act ("ARRA" or "stimulus plan") has numerous provisions designed to provide funding for renewable energy and energy efficiency projects in the United States. This memorandum summarizes the following relevant sources of funding allocated to the state of Michigan, including sources for which utilities and other organizations may apply: the Weatherization Assistance Program, the State Energy Program, the new Energy Efficiency and Conservation Block Grant Program, and various other sources of federal funds.

Weatherization Assistance Program

The Weatherization Assistance Program helps low-income households to permanently increase energy efficiency in their homes, thereby reducing their energy use, energy bills, and carbon emissions. Measures qualifying for support under the Weatherization Assistance Program include: insulation of attics, crawl spaces, walls and ducts; space-heating equipment; energy-efficient windows, refrigerators, water heaters, and air-conditioners; air sealing; repairs to roofs, doors, and windows, compact fluorescent light bulbs; low-flow showerheads; and client education. The DOE provides funding and technical guidance to states, but the states run their own programs, setting eligibility rules and selecting service providers. The ARRA amends the Weatherization Assistance Program such that families making less than 200% of the federal poverty level (approximately $44,000/year for a family of four) are eligible to review up to $6,500 per home in energy efficiency upgrades.[1] Approximately $243 million is allocated to the Weatherization Program in Michigan under the ARRA.

State Energy Program

[1] United States Department of Energy. *Obama-Biden Administration Announces More Than $122.3 Million in Weatherization Funding and Energy Efficiency Grants for Louisiana*. Press Release. March 12, 2009. Available at: http://www.energy.gov/7012.htm

More than $82 million was allocated to the Michigan's State Energy Program through the ARRA. Funds provided through this Program are intended to support energy efficiency and renewable energy projects in individual states, and various states have proposed plans that prioritize energy savings, increase the use of renewable energy, and reduce greenhouse gas emissions, all while creating or retaining jobs.[2] Approximately 40% of the total allocation for Michigan ($32 million) was released by the DOE in June 2009,[3] and the state will focus this funding on the following three-year goals:

- Reducing energy consumption in public buildings by 20% by 2012;
- Establishing green communities;
- Creating markets for renewable energy systems; and
- Creating sustainable jobs in energy efficiency and renewable energy sectors.

In addition, the state will use a portion of these funds to conduct onsite energy audits in 500 homes and businesses through a partnership with two major Michigan utilities.[4]

Energy Efficiency and Conservation Block Grant Program

The Energy Efficiency and Conservation Block Grant Program (EECBG) was authorized under the Energy Independence and Security Act of 2007 (the EISA), but was funded for the first time under the ARRA.[5] Funding is based partly around population and energy use, and the total amount available to Michigan under the EECBG is approximately $76 million. These funds may be allotted to state, county, city, and tribal governments under grants issued by the DOE's Office of Weatherization and Intergovernmental Programs. Funds may be used for the following:

- Energy audits in residential and commercial buildings;
- Energy efficiency retrofits in residential and commercial buildings;
- Development and implementation of advanced building codes and inspections;
- Creation of financial incentive programs for energy efficiency improvements;
- Transportation programs that conserve energy;
- Projects to reduce and capture methane and other greenhouse gas emissions from landfills;
- Renewable energy installations on government buildings;
- Energy efficiency traffic signals and street lights; and

[2] United States Department of Energy. *Obama Administration Announces More Than $32 Million for Energy Projects in Michigan*. Press Release. June 22, 2009. Available at: http://www.energy.gov/7483.htm
[3] The initial 10% of funds was released for planning activities and the remaining 50% will be released when Michigan meets reporting, oversight, and accountability milestones required by the ARRA.
[4] United States Department of Energy. *Obama Administration Announces More Than $32 Million for Energy Projects in Michigan*. Press Release. June 22, 2009. Available at: http://www.energy.gov/7483.htm
[5] Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5).* Report for Congress. March 3, 2009. Page 6.

- Deployment of combined heat and power (CHP) and district heating and cooling systems.

The deadline for applications under the EECBG is June 25, 2009 at 8:00 PM EST for all applicants. A second funding allocation is expected to be made available at a later date.

Other Federal Funding Sources

Other sources of funding for renewable energy and energy efficiency programs include the following:

- *Extension of the Production Tax Credit*: A Production Tax Credit (PTC) provides a 2.1-cent per kilowatt-hour federal income tax credit for the first ten years of a renewable energy facility's operation based on the electrical output of the facility. The ARRA extends the PTC for three years for electricity generated from wind facilities placed into service by December 31, 2012. Other technologies eligible for a PTC include, geothermal, biomass, hydropower, landfill gas, waste-to-energy and marine facilities if they are placed in service by December 31, 2013.[6]
- *Expansion of the Investment Tax Credit*: An Investment Tax Credit (ITC) reduces federal income taxes based on capital investment in renewable energy projects. Under the ARRA, wind, geothermal, biomass and other technologies eligible for the PTC have the option of instead utilizing the 30% ITC (in lieu of the PTC). Expiration dates under the ITC are the same as under the PTC.[7]
- *Grant Program for Renewable Technologies in Lieu of Tax Credits*: Rather than utilize a Production Tax Credit or Investment Tax Credit for new renewable energy projects, project developers may apply for a cash grant from the Treasury Department equal to 30% of the cost of eligible projects. Eligible projects are those renewable energy projects that are placed in service in 2009-2010, or that begin construction during 2009-2010 and are placed in service by 2013 for wind, 2017 for solar, and 2014 for other technologies.[8]
- *Clean Renewable Energy Bonds*: The ARRA provides $1.6 billion in new Clean Renewable Energy Bonds (CREBs) for eligible technologies owned by governmental or tribal entities, and municipal utilities and cooperatives. Eligible technologies include wind, closed-loop biomass, open-loop biomass, geothermal, small irrigation, hydropower, landfill gas, marine renewable, and trash combustion facilities. Qualifying projects of state, local, and tribal governments

[6] Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5).* Report for Congress. March 3, 2009. Page 18.
[7] Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5).* Report for Congress. March 3, 2009. Page 18.
[8] Mark Bolinger, Ryan Wiser, Karlynn Cory, and Ted James. *PTC, ITC, or Cash Grant?: An Analysis of the Choice Facing Renewable Power Projects in the United States.* National Renewable Energy Laboratory. March 2009. Page 3. Available at: http://eetd.lbl.gov/ea/emp/reports/lbnl-1642e.pdf

will receive one-third of CREB funding, public power providers will receive one-third, and electric cooperatives will receive the final one-third.[9]

- *Energy Conservation Bonds*: Energy Conservation Bonds (ECBs) were established by the Emergency Economic Stabilization Act of 2008 with an initial funding allocation of $800 million.[10] The stimulus plan increased that allocation to $2.4 billion. State and local governments will issue the bonds for projects such as:
    - Capital expenditures to reduce energy use in buildings by at least 20%, including publicly owned buildings;
    - The implementation of green community programs;
    - Development of electricity from renewables in rural areas;
    - Research and development of cellulosic ethanol or other non-fossil fuels;
    - Development of technologies that will capture and sequester CO_2;
    - Conversion of agricultural waste for fuel production;
    - Technologies to reduce peak electricity demand; and
    - Public education campaigns to promote energy efficiency.[11]

[9] American Council on Renewable Energy. *Overview: Renewable Energy Provisions American Recovery and Reinvestment Act of 2009*. Page 3. Available at: http://www.acore.org/files/images/email/acore_stimulus_overview.pdf

[10] Tax credit bonds like CREBs and ECBs pay the bondholders by providing a credit against their federal income tax. While normal bonds pay interest to the holders, in the case of CREBs and ECBs, the federal government in effect pays the interest via tax credits. The purpose of CREBs and ECBs is to provide interest-free financing for clean energy projects.

[11] Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5).* Report for Congress. March 3, 2009. Page 19.

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Memorandum

To: NRDC and Sierra Club

From: Synapse

Date: June 26, 2009

Re: Critique of the EPRI *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: 2010 - 2030*, dated January 2009

The Electric Power Institute (EPRI) published a technical report in January 2009 entitled *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.* The study purports to calculate the percentage of energy efficiency and demand response that can be achieved in the US by 2030. This summary memo provides a critique of this technical report. It should be noted that this critique references solely the Executive Summary of this report, as that is the only portion that has thus far been made available for our analysis. Based on that portion of the study, however, we believe that EPRI makes assumptions and uses methodologies that likely underestimate the achievable potential for energy efficiency programs over the next twenty years.

New codes, standards, and regulatory policies for energy efficiency are not considered in the EPRI assessment of achievable efficiency.

EPRI estimates of savings from energy efficiency are for codes, standards, and voluntary utility-operated programs that are currently in existence. They do not include new building codes, efficiency standards for equipment and/or appliances, new utility-sponsored programs, or programs administered by states or third parties. These new codes and standards will likely include measures that are not considered in this study, and may also increase the penetration rate of existing measures to a level that is much higher than that assumed by EPRI.

Estimates of energy efficiency savings are limited by the use of existing technologies only.

EPRI bases its estimates of energy efficiency savings on types of technology that are currently commercialized and cost-effective, e.g. lighting, appliances, etc. and it does not account for any innovations in these technologies over time or the addition of new technologies.

Existing equipment is assumed to be in use through the end of its useful life. However, energy-efficiency incentives can encourage early retirement in favor of more efficient equipment.

EPRI assumes that energy efficiency technologies will not "instantaneously or prematurely"[1] replace existing equipment, but rather will be phased-in as devices reach the ends of their useful lives. Utility or government incentives, however, may lead to the replace of these less efficient devices well before the end of their useful lives.

The useful life of energy efficiency devices is assumed by EPRI to be less than 15 years, while the period of this study is 20 years. Some efficient devices installed prior to the study period or at the beginning of the study period will reach the end of their useful lives well before 2030, but because EPRI allows for no new technologies as replacements, no new opportunities for energy efficiency can be created.

Estimates of savings include energy efficient technologies, but do not include as many energy efficient processes as may be practicable.

Energy efficient *technologies* are the drivers behind EPRI estimates of savings. These estimates include few energy efficient *practices* or *processes*. This criticism applies especially to estimates of industrial savings. EPRI's estimates include only motor, lighting and heating improvements made by industrial customers. Including the wide variety of available industrial process improvements, as well as improved system designs for buildings, would increase estimates of energy efficiency potential.

The assumption that incremental costs for energy efficiency technologies will remain constant is flawed.

EPRI holds costs for energy efficiency technologies constant over the 20 year study period. This causes two errors in the estimates for economically achievable energy efficiency potential. The first errors occurs due to the fact that costs for technologies that are currently commercially available are likely to fall over time, and estimates of energy efficiency potential can therefore be achieved at a reduced cost. The second error occurs because certain efficiency technologies may fall into the efficiency category of "Technical Potential" which represents the amount of energy efficiency that could occur if all homes and business adopted the most efficient technologies available irrespective of cost. Technologies that are too expensive, while they may be available, are unlikely to be adopted by consumers. As the cost for these technologies falls, however, they are more likely to pass screens for economic cost-effectiveness and move into the efficiency category of "Economically Achievable Potential" and actually be put into service.

Use of the Participant Cost Test may not properly measure cost-effectiveness, and may therefore underestimate achievable potential.

The Participant Cost Test is one example of the cost-effectiveness screens mentioned above that measures cost of a program from the perspective of the customer. Most customers pay a flat rate per kWh of electricity, and so this test ignores savings that occur during peak hours of the day, e.g. those related to more efficient measures for space

[1] Electric Policy Research Institute. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: 2010 – 2030. Executive Summary*. January 2009. page 8.

cooling. The particular test also does not account for benefits that accrue due to avoided demand. Peak energy and avoided demand savings are much more valuable from a utility or total resource perspective, and efficiency measures that result in these types of savings would pass the corresponding screens for cost-effectiveness – the Utility Cost Test and the Total Resource Cost Test – that would not pass the Participant Cost Test.

EPRI assumes a relatively flat electricity price forecast in real dollars through 2030.

As electricity prices rise, customers are more likely to commit to energy efficiency measures, resulting in increased energy savings. Peak energy savings and avoided demand are also much more valuable as prices increase.

To summarize, EPRI makes many flawed assumptions in its report, holding technological progress, incremental cost of technologies, and national electricity prices flat over time. Maximum energy efficiency potential as estimated by EPRI reaches 8% energy savings by the year 2030, and the realistic savings estimate is only 5% in 2030. EPRI's estimate represents an incremental load savings of approximately 0.2% per year. While average energy efficiency savings was 0.24% in 2006, as reported by the American Council for an Energy-Efficient Economy (ACEEE) and cited by EPRI in its study,[2] it is critical to note that this is an average across the entire United States, and therefore includes states that are attempting absolutely no energy efficiency. This consequently brings down the national average by a significant margin. The most important critique of EPRI's estimate, therefore, is that *in practice*, many jurisdictions are *already* beating 0.2% savings per year by a wide margin, some by more than an order of magnitude. As reported by FERC in April 2009, the following states are leading the nation in their goals for energy efficiency:[3]

- Minnesota: 1.5% annual savings from prior year's sales to 2015;
- Ohio: reduce peak demand 8% by 2018 and achieve energy savings of 22% between 2009 and 2025;
- Maine: 10% energy efficiency by 2017;
- Massachusetts: 25% of electric load from demand response and energy efficiency by 2020;
- Maryland: 15% reduction in electricity use and peak from 2007 levels by 2015;
- New York: 15% reduction in electric use by 2015 from levels projected in 2008; and
- Vermont: 2% annual energy savings between 2009 and 2011.

[2] Electric Policy Research Institute. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: 2010 – 2030. Executive Summary*. January 2009. page 7.
[3] Federal Energy Regulatory Commision. *Electric Market Overview: Energy Efficiency Resource Standards (EERS) and Goals*. Updated April 3, 2009.